S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **WISCONSIN ELECTRIC POWER COMPANY** for authority to increase its rates for the sale of electricity in the State of Michigan and other relief.	)))))	Case No. U-16830

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on April 30, 2012.

Exceptions, if any, must be filed with the Michigan Public Service Commission, P.O. Box 30221, 6545 Mercantile Way, Lansing, Michigan 48909, and served on all other parties of record on or before May 14, 2012, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before May 21, 2012. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Mark E. Cummins

Digitally signed by Mark E. Cummins
DN: cn=Mark E. Cummins, c=US, email=cumminsm1@michigan.gov
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Mark E. Cummins
Administrative Law Judge

April 30, 2012
Lansing, Michigan

S T A T E O F M I C H I G A N

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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<u>PROPOSAL FOR DECISION</u>

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BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application of **WISCONSIN ELECTRIC POWER COMPANY** for authority to increase its rates for the sale of electricity in the State of Michigan and other relief.	)))))	Case No. U-16830

PROPOSAL FOR DECISION

I.

HISTORY OF PROCEEDINGS AND POSITIONS OF THE PARTIES

The Wisconsin Electric Power Company (WEPCo or the Company), a subsidiary of Wisconsin Energy Corporation (WEC), is a public utility engaged in the generation and distribution of electricity and other related services. Although a great majority of its customers are located in Wisconsin, WEPCo also provides retail electric service in the western two-thirds of Michigan's Upper Peninsula. At present, WEPCo serves its jurisdictional electric customers in Michigan under rate schedules and charges established by the Commission's July 1 and October 14, 2010 orders in Case No. U-15981. In addition, the Commission has also authorized--through its various orders--the recovery of certain additional costs as set forth in the tariffs on file with the Commission, including power supply cost recovery (PSCR) factors.

On July 5, 2011, WEPCo filed an application, with supporting testimony and exhibits, seeking authority to increase its base rates by approximately $17.5 million on an annual basis, subject to some partially offsetting credits. According to the Company, "the most significant cost drivers" giving rise to its asserted need for increased revenue include: (i) additional capital investments designed to both increase system reliability and comply with environmental and other requirements; (ii) a more accurate recognition in base rates of WEPCo's investment in, and the related operating costs of, its hydro-driven facilities; (iii) changes in the utility's projected sales levels; and (iv) the inclusion in rates of various lease payments and deferred pre-lease expenses related to the Company's Elm Road Generating Unit 2 (ERGS-2), which--the application points out--came on line in January of 2011. WEPCo's application, p. 2. With regard to the above-mentioned credits, the utility stated that its requested revenue requirements also reflect, among other things, reductions in non-fuel Operation and Maintenance (O&M) expense and the impacts of "Bonus depreciation." Id. Moreover, the application sought to implement, subject to reconciliation, the "appropriate credits to provide customers the Michigan allocated portion of the net benefits of the settlement reached in Wisconsin Electric Power Co v The United States, Court of Claims Docket No. 00-679C" (DOE Settlement), which the Company asserts would serve to reduce its requested annual revenue increase from $17.5 million to a net increase of about $14.9 million. Id., p. 4. Finally, WEPCo proposed having the Commission address the treatment of the "hypothetical gain from any imputed purchase price to be determined in the reopened proceeding in Case No. U-16366," which involved the utility's recent sale of its 25% ownership interest the Edgewater Unit 5 generating facility (Edgewater-5). Id.

Pursuant to due notice, a prehearing conference was held in this matter on August 19, 2011, before Administrative Law Judge Mark E. Cummins (ALJ). In addition to WEPCo and the Commission Staff (Staff), several potential intervenors also filed appearances and participated at the prehearing. Intervention was granted on that date to the following parties, grouped collectively as appropriate: Tilden Mining Company L.C. and Empire Iron Mining Partnership (the Mines); Louisiana-Pacific Corporation (LPC); and Verso Quinnisec, LLC (Verso). The parties then proceeded to establish a consensus schedule to cover all subsequent activities in this proceeding.[1]

Consistent with that schedule, an evidentiary hearing was held on December 13, 2011, regarding potential self-implementation of the utility's requested rate increase. In the course of that hearing, the testimony of James A. Schubilske--who serves as an Assistant Treasurer for WEPCo, its affiliate Wisconsin Gas LLC, and their parent company, Wisconsin Energy Corporation (WEC)--was bound into the record, and all sections of his accompanying exhibit were received into evidence. Based on that evidence, WEPCo requested authority to self-implement a rate increase in the amount of $5,648,807 annually, concurrently implement a countervailing credit of $2,694,144 concerning proceeds received from the above-mentioned DOE settlement, and apply an

[1] This matter represents WEPCo's second fully-litigated general rate case since Act 286 of 2008, MCL 460.6a, et seq., (Act 286) took effect on October 6, 2008. As noted by the Commission on page 3 of its May 26, 2009 order in Case Nos. U-15768 and U-15751, "Act 286 established extremely short timeframes for concluding rate cases" such as this. For example, Section 6a(1) of Act 286 provides that if the Commission has not issued an order within 180 days of the filing of a complete application for a rate change, the utility may self-implement any portion of its proposed change through "equal percentage increases or decreases applied to all base rates" (although, if the utility's proposal is based upon a projected test year, self-implementation shall not occur prior to the start of the projected 12-month period). MCL 460.6a(1). Moreover, Section 6a(3) requires the Commission to issue its final order within 12 months following receipt of a complete rate case filing, lest the application be considered approved. See, MCL 460.6a(3). Much to their credit, the parties to the present case agreed to a schedule that would allow the Commission to meet the various deadlines imposed by Act 286.

alternative rate design instead of the statutory equal-percentage default rate design. See, 2 Tr 19-22, and Exhibit A-18. Although none of the other parties offered evidence of their own regarding self-implementation, the Staff, the Mines, and LPC filed--in advance of the December 13, 2011 hearing--responses to WEPCo's proposal. On December 20, 2011, the Commission issued an order adopting the utility's proposal.

Evidentiary hearings concerning the remainder of these consolidated cases took place on January 23, 2012. WEPCo offered testimony and exhibits from 6 additional witnesses (not counting Mr. Schubilske), while the Staff offered testimony and exhibits from a total of 10 witnesses. In addition, the Mines submitted testimony from two witnesses and Verso sponsored one, each of which offered exhibits relating to their respective testimony. When combined with evidence received during the December 13, 2011 hearing, the entire record consists of 590 pages of transcript and 182 exhibits.[2] Consistent with the agreed upon schedule for this case, each of the parties filed initial briefs on March 1, 2012, as well as reply briefs on March 19, 2012.

Both WEPCo and the Staff performed a full cost-based analysis of the utility's likely financial situation for 2012 and beyond. After undertaking an audit of WEPCo's financial data, the Staff computed the Company's Michigan-related revenue deficiency to be approximately $11.7 million, which it then reduced by both the $2,694,000 DOE settlement and a suggested recognition of $368,912 in liquidated damages paid to the utility by Bechtel Construction Company (Bechtel), thus reaching a net revenue deficiency of just over $8.6 million. See, Exhibit S-1, Schedule A-1. In coming up with

[2] Although one additional document--designated as S-5--was included as part of the Staff's pre-filed presentation, that document was neither offered nor received into evidence.

that net figure,[3] the Staff applied--based on testimony submitted by its witness regarding cost of capital issues--a 9.95% rate of return on common equity, in contrast to WEPCo's request to increase that rate of return from its currently-authorized level of 10.25% to 10.4%. After reviewing the Staff's testimony, WEPCo elected to accept, "for purposes of this case," several of the revenue deficiency adjustments proposed by the Staff. See, WEPCo's initial brief at p. 2 and its reply brief at p. 3. The utility thus now asserts that, as reflected on Attachment A to its reply brief, the Michigan-related portion of its total company revenue deficiency for 2012 will be $12,616,041.

The Mines requests several other adjustments to the Company's proposal, which, when taken together, produce a revenue sufficiency (as opposed to a deficiency) of approximately $16.8 million. See, Mines' initial brief, p. 4; Exhibit MIN-1. LPC also proposes numerous adjustments to the utility's figures, concludes that a revenue sufficiency exists for WEPCo, and thus asks the Commission to deny the utility's requested rate increase in its entirety. See, LPC's initial brief, pp. 8-9. Finally, although not offering its own specific calculation, Verso does not believe that the Company has justified its alleged revenue deficiency. See, Verso's initial brief, p. 3.

As in most cases of this nature, a large amount of testimony and argument has been presented with regard to issues that are both numerous and complex. In addition to the typical matters arising in general rate cases like this, a significant portion of the record also deals with (1) costs arising from WEPCo's lease agreements regarding both ERGS Unit 1 [ERGS-1] and EGRS-2, (2) expenses related to the Company's

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[3] It bears noting that, in computing its $8.6 million revenue deficiency figure, the Staff does not appear to have actually included the effects of either its proposed adjustment to rates to reflect the performance of EGRS Unit 1 during its first 8 months of operation, or its requested treatment of the proposed imputed price premium arising from the utility's sale of its interest in Edgewater-5. Compare, Staff's initial brief at pp. 38-54 and Exhibit S-1, Schedule A-1.

participation in the Power the Future [PTF] project, (3) the suggested allocation of costs incurred from the utility's involvement in renewable energy [RE] activities, (4) rate credits tied to various legal and other activities, and (5) disputes arising from Verso's special contract with WEPCo. Despite the number and complexity of these various concerns, Act 286 requires (as noted in footnote 1, supra) the issuance of a Commission decision within 12 months after the application's filing. Thus, in the interest of issuing this Proposal for Decision (PFD) in a timely manner, not all of the material presented in this case will be expressly discussed. The various parties' summaries of the evidence and arguments in support of their respective positions are fully set forth in their pleadings, briefs, and reply briefs, and the underlying basis for the same can be found in the evidentiary record. Thus, although the ALJ has considered the entire record in arriving at the findings and conclusions expressed below, only those arguments, testimony, and exhibits that are necessary for a reasoned analysis of the disputed issues will be specifically addressed in the PFD.

II.

TEST YEAR

In every general rate case, the initial task is the selection of an appropriate test year. Essentially, this task is comprised of two components.

First, a decision must be made regarding the 12-month period to use in setting the utility's new rates. In this case, both WEPCo and the Staff proposed using a 2012 test year for that purpose. Moreover, the Mines' calculation of their asserted revenue sufficiency for the utility appears to have also been based upon a 2012 test year, and neither LPC nor Verso objected to its use. Thus, due to the lack of any disagreement, the ALJ recommends adopting that 12-month period for use in this case.

Second, a determination must be made regarding how to best establish values for the various levels of revenue, expenses, rate base, and capital structure used in the rate-setting formula. Generally, these values may consist of historical, future, or a combination of historical and future data. A historical test year uses actual operating data that, once audited, is generally adjusted for known and measurable changes. A future test year (frequently referred to as a projected test year) uses projections to determine the levels of revenue, expenses, rate base, and capital structure for a future period of time.

Although parties often have disputes regarding what type of test year is most appropriate in a given case, the Commission has consistently expressed a preference for using historical, as opposed to purely projected, data. See, i.e., the Commission's November 7, 2002 order in Case No. U-13000, at p. 13. Nevertheless, Section 6a(1) of Act 286 states that a utility may "use projected costs and revenues for a future consecutive 12-month period" to develop its requested gas or electric rates and charges. MCL 460a(1). This statutory provision has altered the debate somewhat by specifically indicating that Michigan's regulated gas and electric utilities have the right to base their general rate case filings exclusively upon projections of anticipated activities and their related expenses, should they so desire. Nevertheless, what it does not do, however, is demand that either the parties or the Commission blindly accept any and all numbers springing from a utility's projections of future actions and the potential costs arising from those actions.

The Commission recently acknowledged this fact in its January 11, 2010 order in Cases Nos. U-15768 and U-15751 (the January 11 order), where it stated that:

> In a case where a utility decides to base its filing on a fully projected test year, the utility bears the burden to substantiate its projections. Given the time constraints under Act 286, all evidence (or sources of evidence) in support of the company's projections should be included in the company's initial filing. If the Staff or intervenors find insufficient support for some of the utility's projections, they may endeavor to validate the company's projections through discovery and audit requests. If the utility cannot or will not provide sufficient support for a particular revenue or expense item (particularly for an item that substantially deviates from the historical data) the Staff, intervenors, or the Commission may choose an alternative method for determining the projection.

January 11 order, p. 9.

Here, WEPCo and the Staff based their testimony and exhibits on a projected test year, and none of the other parties objected. However, as correctly noted by the utility, both the Staff and the Mines went on to "recommend several adjustments to the Company's 2012 projections based upon historical information." WEPCo's initial brief, p. 15. As a result, the test year information provided by the utility will be used as the starting point for discussions concerning the various issues raised in this case, with the other parties' proposed adjustments addressed as needed.

III.

RATE BASE

The rate base for an electric utility like WEPCo consists of the capital invested in all used and useful plant and property, less accumulated depreciation, plus the utility's working capital requirements. However, since this utility is a multi-state operation, the focus here is on the portion of its rate base that is assigned to Michigan ratepayers.

Although initially proposing slightly different rate base figures, both on a total company and a jurisdictional/Michigan-only basis, WEPCO now adopts the Staff's recommendation to set total company rate base for the test year at $6,298,174,921, consisting of $5,630,029,911 in net plant and $668,145,010 of working capital. See, Exhibit S-2, Schedule B1; WEPCo's reply brief, p. 4. As further noted by the utility, and as set forth on a related exhibit offered by the Staff, this corresponds to a jurisdictional 2012 test year rate base of $354,886,352.[4] See, Exhibit S-1, Schedule A-1. Although not offering specific calculations concerning rate base, both the Mines and Verso assert that a lower level of net plant should be used in establishing WEPCo's rates. Specifically, these two intervenors contend that the Company's net plant should not reflect capital additions to the Oak Creek (OC) Air Quality Control System (AQCS) for Units 5 through 8.

A. Net Utility Plant

As noted above, the only issue regarding the level of net utility plant adopted for use in this case concerns the assertion--first offered by the Mines, and subsequently adopted by Verso--that $857 million in capital additions for OC Units 5 through 8 should be excluded from rate base because the in-service dates for their AQCS systems are too uncertain. See, Mines' initial brief, pp. 12-14; Verso's reply brief, pp. 9.

In support of this assertion, the Mines' contend that "the projected in-service dates for the [OC AQCS] that WEPCo's witness [David J. Ackerman] supports in this proceeding are dramatically different than the planned in-service dates in WEPCo's

[4] As specifically noted by both the utility (on page 15 of its initial brief) and the Staff (on Exhibit S-1, Schedule A-1), this figure relates solely to Michigan-based retail customers, excluding those taking service under special contracts.

application for approval of the project." Mines' initial brief, p. 12. Specifically, the Mines point out that, in the present case, Mr. Ackerman indicated that the AQCS for OC Units 5 and 6 would likely be placed in-service in December, 2011, and that the accompanying systems for Units 7 and 8 would be transferred to in-service status during April, 2012. However, the Mines go on to note that when the Company initially sought approval from the Public Service Commission of Wisconsin (PSCW) to invest in AQCS, it envisioned in-service dates of March 1, 2012, for OC Units 7 and 8, as well as December 1, 2012, for Units 5 and 6. See, Id., citing Exhibit MIN-10. The Mines thus assert that "one cannot determine from the record in this proceeding when WEPCo will place the new AQCS into service." Id., p. 13. As a result, both they and Verso argue that "the Mines' proposed adjustments [to net plant] should be adopted." Verso's reply brief, p. 9.

Based on his reading of the record, the ALJ does not find the above-described arguments persuasive for several reasons. First, neither the Mines nor their witness on this particular topic (Michael P. Gorman, an independent public utility consultant) identified any specific reason or circumstance supporting the theory that the projected in-service dates offered by the utility in this proceeding will not be met. Second, as noted by the Company and acknowledged by Mr. Gorman, the proposed rates requested in this case provide cost recovery for the AQCS-related investments for only part--and not all--of the 2012 test year. See, WEPCo's initial brief, p. 16.

Third, and most importantly, the totality of the evidence supports the utility's projected in-service dates for these various facilities. For example, Mr. Ackerman testified that "all four units will be in service by mid-2012." 3 Tr. 51. In addition, his rebuttal testimony stated that, as of WEPCO's filing in December, 2011, the entire OC AQCS project was already 91% complete. See, Id., at 99. Moreover, based on a consent decree between WEPCo and the U.S. Environmental Protection Agency (EPA), the Company has no choice but to ensure that the AQCS for each of those OC Units is on line by the close of 2012. See, Id. Finally, as stated by Daniel M. Birkam, an Auditor in the Revenue Requirements Section of the Staff's Regulated Energy Division:

> Staff, in examining the Company's projections, has found no evidence that the construction on the project is not on schedule. Staff also notes that by the consent decree with the EPA mentioned on page 9 of Company witness Ackerman's testimony, the Company must have the Oak Creek AQCS completed by the end of the projected test year, and on page 10 that the project is expected to be in service by mid-year 2012, which is the test year in this rate case. Staff further notes that according to Company Exhibit A-17, Schedule J2, page 2, [WEPCo] gas a 100% AFUDC offset for the CWIP associated with this project as approved by [the PSCW], and as explained below, Staff supports the continued use of [the] Wisconsin AFUDC calculation for Michigan rates for WEPCo. Finally, Staff notes that because of this 100% offset for CWIP, the Oak Creek AQCS is only getting half a year of rate recovery in the projected test year. This half year coincides with [when] the completed project will be put in service, and the expected date of the final order in this case. Therefore, the Staff finds the Company's projections for the Recovery of the Oak Creek AQCS to be reasonable.

3 Tr 505-506.

For all of these reasons, the ALJ finds that the most appropriate net plant figure to use when setting WEPCo's Michigan-assigned rates for the 2012 test year is that initially proposed by the Staff and subsequently adopted by the Company.

B. Working Capital

Working capital is the amount of funds required to bridge the gap between the time of payment of a utility's expenses and the receipt of revenues from its customers. In this case, the Staff and WEPCo propose slightly different figures for the Company's total electric working capital allowance. Based on its use of the balance sheet methodology approved by the Commission's June 11, 1985 order in Case No. U-7350, the Staff projected a working capital requirement of approximately $668.1 million for the projected test year ending December, 2012. See, 3 Tr 496; Exhibit S-2, Schedule B4. The Company, on the other hand, proposed setting its working capital figure at about $646.8 million. None of the other parties provided either testimony on the appropriate level to be used in setting rates or a separate economic analysis of the issue.[5]

According to Kavita R. Bankapur, a Financial Analyst in the Staff's Regulated Energy Division, the difference between the Staff's figure and that sponsored by the utility reflects the effect on working capital of the Staff's proposed $21.3 million reduction to "other deferred credits and liabilities." 3 Tr 497. Specifically, Ms. Bankapur testified that this adjustment is necessary to account for the Staff's proposed reduction in overall O&M expenses, and "is consistent with the Commission's disallowance of incentive compensation [as an O&M expense component] in previous rate cases. Id. WEPCo specifically conceded that "if incentive compensation expenses are removed from O&M expenses, the deferred credits and liabilities related to such incentive compensation should likewise be removed from the calculation of working capital," as the Staff recommended. WEPCo's reply brief, p. 18. Moreover, the Company subsequently agreed to accept the Staff's proposal to "remove incentive compensation, bonuses, and executive perquisites from its 2012 test year [O&M] expense." Id., p. 108.

In light of the agreement between the Staff and the utility on this issue, as well as the lack of any record-based proposal to the contrary, the ALJ finds that the working

[5] Although Verso did suggest during the briefing phase of the case to start with the utility's lower working capital figure and then reduce that number by $21.3 million, no record-based support (nor any specific financial analysis) was provided in support of that suggestion. See, Verso's reply brief, p. 9.

capital figure proposed by the Staff and set forth both in Ms. Bankapur's testimony and on Exhibit S-2, Schedule B4--specifically, $668,145,010--should be adopted for use in this case.

C. Conclusion

In light of the discussion and recommendations set forth above, the ALJ finds that WEPCo's total company electric rate base for its projected 2012 test year should be set at $6,298,174,921, as depicted on Exhibit S-1, Schedule A-1. This overall figure, which incorporates all of the above-mentioned adjustments, corresponds with a jurisdictional (e.g., Michigan retail customer-only) rate base of $354,886,352.

IV.

CAPITAL STUCTURE, COST OF CAPITAL, AND RATE OF RETURN

As noted in previous Commission orders, the criteria for establishing a fair rate of return for utilities like WEPCo stems from the decisions issued by the United States Supreme Court in Bluefield Water Works Co. v Public Service Comm. of West Virginia, 262 US 679 (1923) and Federal Power Comm. v Hope Natural Gas Co., 320 US 591 (1944). In those cases, (generally referred to as "Bluewater" and "Hope)", the Court made clear that when establishing a fair rate of return for a public utility, consideration must be given to both customers and investors. As stated by the Commission in the past, the rate of return "should not be so high as to place an unnecessary burden on ratepayers, yet should be high enough to ensure investor confidence in the financial soundness of the enterprise." December 23, 2008 order in Case No. U-15244, p. 12. Still, the Commission went on to note that any determination of what is fair and reasonable "is not subject to mathematical computation with scientific exactitude but [rather] depends upon a comprehensive examination of all factors involved, having in mind the objective sought to be attained in its use." Id., [citing Meridian Twp. v City of East Lansing, Mich., 342 Mich 734, 749 (1955)].

With these time-tested principles in mind, we turn to the factors forming the basis for what rate of return should be adopted in this particular proceeding. Specifically, to reasonably estimate WEPCo's revenue requirement, it is necessary to select a rate of return to be applied to the utility's rate base. This involves a two-step process. The first is determining the appropriate capital structure, that is, the relative percentages of debt, equity, and deferred income taxes used to fund the utility's overall operations. The second is determining the proper cost rate for each component of the capital structure.

Despite differing views regarding what rate of return should be established in this case,[6] the parties have been able to reach agreement concerning several components of WEPCo's capital structure and the respective costs of the utility's sources of capital.[7] Thus, the only areas of contention that must be addressed in this PFD concern (1) the amount of common equity to include in the Company's capital structure, (2) the Staff's proposal to add approximately $66 million of deferred income taxes [DIT] to that capital structure, (3) the appropriate cost of long-term debt, (4) the imputed cost of short-term

[6] While WEPCO claims that its weighted, after-tax overall rate of return should be 6.80%, the Staff suggests using 6.28% and the Mines recommend that 6.08% should be adopted. See, Exhibit A-4, Schedule D1; Exhibit S-4, Schedule D1; and 3 Tr 330.

[7] Notwithstanding the fact that (because they were based on the parties' respective "as-filed cases"), the specific dollar values attached to each component of WEPCo's capital structure will vary from what is recommended in the PFD, as well as what is actually approved by the Commission's final order in this case, the percentages should remain relatively consistent throughout, thus allowing the utility, the Staff, and any interested party to make the final calculation once the Commission issues its order.

debt, and (5) the most reasonable rate of return to be allowed on WEPCo's common equity. Each of these five issues is addressed below.

A. Capital Structure

WEPCo initially proposed the use of a permanent capital structure consisting of approximately 44.16% debt and 55.84% equity (with 55.30% of that total equity--or $3,093,168,536--constituting common equity), which it believed to be consistent with its likely capital structure for the 2012 test year. Exhibit A-4, Schedule D1. The Staff agreed with each of those estimates, as reflected on Exhibit S-4, Schedule D1. The only parties to recommend any change to the permanent capital structure percentages offered by the utility and Staff were the Mines, who proposed reducing the Company's common equity level to remove certain investments in American Transmission Company, LLC (ATC), Bostco, and other non-utility property. See, Mines' initial brief, at p. 6. As for WEPCo's total (as opposed to permanent) capital structure, the only requested revision came from the Staff, which advocated adding approximately $66 million to the utility's suggested DIT balance.

1. Common Equity in Permanent Capital Structure

As shown on Exhibit A-4, Schedule D5, the utility's witness concerning the appropriate level of common equity to include in its permanent capital structure, Mr. Ackerman, began with the total electric company's 13-month average common equity balance ($3,331,258,373), and then reduced that figure by the 13-month average investment in ATC ($220,962,081), the 13-month average investment in Bostco ($3,020,313), and the 13-month average investment in other non-utility property

($14,107,444). In contrast, The Mines' witness on this issue, Mr. Gorman, asserted that Mr. Ackerman "significantly understated" the reduction in common equity investment that is needed to fully remove WEPCo's investments in non-regulated companies. 3 Tr 331. Specifically, he provided direct testimony indicating that:

> [O]n the Company's consolidated balance sheets for December 31, 2010, the amount of investments in non-regulated companies is $291.1 million. [Citing WEPCo's Securities and Exchange Commission (SEC) Form 10-K, issued 12/31/10, at p. 68]. These equity investments include investments [in] ATC of $290.6 million, and other non-utility equity investments of $0.5 million. In that same SEC Form 10-K, WEPCo informed its investors that it planned on making another $17 million investment in ATC over the next three years. [Id., at 36].
>
> Based on these representations for the calendar year ending December 31, 2012, I propose to make equity adjustments of $350 million of ATC, and $45 million for other non-regulated business entities. This results in total equity adjustments to regulated cost of service of $396.3 million.

3 Tr. 331. Mr. Gorman went on to state that "based on the information provided on my Exhibit MIN-2, . . . the amount of common equity of total investor long-term capital decreases to 54.70%, from the Company's proposed [level of] 55.30%. Id.[8]

WEPCo takes issue with increasing the total amount of the ATC and Bostco adjustments as proposed by the Mines, and cites two reasons for rejecting any such increase. First, the Company argues that the information cited in the utility's December 31, 2010 SEC Form 10-K does not support Mr. Gorman's stated proposal to increase the ATC investment adjustment to $350 million. With regard to that proposal, WEPCo relies on the following rebuttal testimony from Mr. Ackerman:

[8] Mr. Gorman went on to point out that, when short-term debt, DIT, and Job Development Investment Tax Credits (JDITC) are factored in, WEPCo's adjusted common equity for the 2012 test year would constitute 43.32% of the utility's total capital structure, as opposed to the 43.92% level estimated by Mr. Ackerman and set forth on Exhibit A-4, Schedule D1. See, Id.

> First, Mr. Gorman's math doesn't add up, or he just doesn't show all of the pieces that would support a $350 million forecasted value for the ATC investment. More importantly, however, [Mr.] Gorman apparently doesn't realize that the ATC investment shown in the SEC Form 10-K filing is a gross value. It is not net of associated deferred income tax balances. The amount of non-regulated investment to be removed from common equity for ratemaking must be net of the associated deferred tax balance as established in the Company's prior rate case. The ATC-related [DIT] balance was more than $90 million at December 31, 2010. With respect to the ATC investment removed by the Company in the 2012 test year, the Company forecasted $13.8 million of new capital investments being made over the two year period of 2011 and 2012, which is consistent with language in the 2010 SEC Form 10-K. In addition, the Company forecasted $126.5 million of earnings net of $101.6 million of dividends, such that $24.9 million would accrue to the estimated ATC investment balance. The amount of the ATC investment removed from common equity by the Company in the 2012 test year is based on a reasonable and appropriate forecast of the ATC investment balance net of its associated [DIT]. Witness Gorman's testimony does not provide enough supporting detail to show how he arrived at his estimate, and what detail he does provide was misinterpreted by him. [Thus], his suggested ATC investment adjustment is not reasonable and should not be adopted.

WEPCo's initial brief, p. 21 [citing 3 Tr. 96-97]. Second, the Company takes issue with Mr. Gorman's suggestion to increase the level of other non-regulated investment from $0.5 million to $45 million, claiming that such a suggestion "is unsupported by any evidence or reasoning." Id. On this point, the utility again relies on rebuttal testimony from Mr. Ackerman, in which he states that:

> Mr. Gorman's estimate is totally unsupported. He points to the actual balance of $0.5 million based on the SEC Form 10-K report, and then simply says it should be $45 million in the [2012] test year without providing any reason or justification. [Therefore], his suggested other non-regulated investment adjustment should be dismissed.

Id. [citing 3 Tr 97]. WEPCo thus argues that the Mine's proposal to increase the size of the non-regulated investment reductions from the utility's proposed capital structure is "erroneous and without basis," and must be rejected. Id. p. 22.

The ALJ does not find WEPCo's arguments persuasive on this matter. As noted in the Mines' reply brief, those arguments essentially ignore the surrebuttal testimony offered by the Company's witness, in which he fully explained the apparent conflict between the numbers cited in his direct testimony and those he was actually relying upon. Specifically, with regard to his initially asserted 2012 ATC investment of $350 million, Mr. Gorman noted that:

> [The] ATC investment number identified on page 12 of my testimony is a typographical error. The amounts recorded on WEPCo's FERC Form 1 are $290.6 million for the ATC equity investment, a planned $17 million additional equity investment in ATC (or $307.6 million), and $5 million equity investment in other non-regulated investments. My adjustment used the correct numbers, as shown in my workpapers, and in my adjustment to WEPCo's capital structure, but the numbers in my testimony are not correct.

3 Tr 457. A review of the related document submitted by Mr. Gorman and marked as Exhibit MIN-2 coincides with his explanation, and thus (when viewed in conjunction with WEPCo's apparent agreement with the figures gleaned from its 2010 SEC Form 10-K) serves to support the Mines' claimed level of non-regulated investment in ATC.

As for the Company's second argument in opposition to the Mines' requested adjustment to the level of common equity to be included in the utility's capital structure--namely, that Mr. Gorman failed to remove accumulated DIT associated with ATC--that argument again seems to ignore significant surrebutal testimony offered on that specific question. In this regard, Mr. Gorman explicitly stated as follows:

> I agree that WEPCo's capital structure should remove both equity capital and accumulated [DIT] associated with investments in non-utility investments and the ATC investment. The amount of equity investments WEPCo made in ATC is not equity capital used to invest in its regulated production and distribution plant in Wisconsin or Michigan. Therefore, the amount of equity capital supporting investments in generation and distribution plant should be separated from the amount of WEPCo equity

> capital invested in equity shares of ATC. The same separation should be made for accumulated [DIT] balances.
>
> Mr. Ackerman did adjust the Company's total balance of accumulated [DIT] to remove the balances supporting non-regulated investments in his direct testimony on Schedule D6. I did not take issue with the Company's removal of balances of [DIT] related to non-regulated investments. Therefore, I am correct to remove all WEPCo common equity capital invested in non-regulated affiliates because I also removed all non-regulated [DIT] balances assignable to non-regulated investments. Therefore, Mr. Ackerman's claim of error is fallacious.

3 Tr 457-458. As noted by the Mines, because "the total amount of accumulated [DIT] associated with WEPCo's investment in ATC was already removed" by the Company when its rate case application was filed, no further accumulated DIT needs to be removed at this point. Mines' reply brief, p. 5. As such, the ALJ concludes that the common equity adjustment advocated by Mr. Gorman, supported by the Mines, and accounted for in the capital structure set forth on Exhibit MIN-2, should be adopted by the Commission.

2. Level of DIT in Total Capital Structure

As part of its overall capital structure, WEPCo included $1,100,464,793 in net DIT. See, Exhibit A-4, Schedule D1, line 6. In contrast, the Staff recommended the inclusion of $1,166,152,184 for net DIT. See, Exhibit S-4, Schedule D1, line 6. The nearly $66 million difference between these two figures is, according to the Staff's witness on this matter, Ms. Bankapur, "related to the [DIT] portion of [the Company's] Wisconsin regulatory assets," which the utility had specifically removed from its proposal. 3 Tr 494. According to her, the entire--as opposed to only the Michigan-related DIT balance--should be reflected in the utility's overall capital structure, as WEPCo's filings propose should be the case with all other utility-owned assets and accounts. See, Id. Specifically, she noted, "the [DIT] balance is the only component of the Company's capital structure that reduces [the] Wisconsin portion of the balance," thus making its exclusion from the utility's proposal highly suspect. Id. Verso agrees with that viewpoint, and thus concludes that "the Staff's adjustment is reasonable and should be adopted by the Commission." Verso's reply brief, p. 8.

According to the Company, the Staff's proposed level of DIT to be reflected in the utility's total capital structure "is without merit, unsupported, unreasonable and should be rejected." WEPCo's initial brief, p. 22. Among other things, the Company's witness on this issue, Mr. Ackerman, asserted that:

> By removing the Wisconsin deferred regulatory assets from Michigan's working capital in rate base, the Michigan customer receives the benefit of a lower jurisdictional revenue requirement—which the Company believes is reasonable and appropriate. But, if the DIT balance used as zero cost capital in the required rate of return is not reduced by the associated DIT created by these same regulatory assets, the Michigan customer would get a Wisconsin jurisdictional deferred tax benefit which would not be reasonable and appropriate.

Id., p. 23 [citing 3 Tr 90]. Moreover, WEPCo points out that in the course of its July 1, 2010 order in Case No. U-15981 (the July 1 order), the Commission:

> found that the Staff did not adequately identify how or why it was appropriate to include the Wisconsin jurisdictional amount of DIT associated with Wisconsin regulatory assets removed from Michigan rate base as zero cost capital, and therefore adopted the Company's DIT estimate as adjusted to remove the Wisconsin related DIT.

Id., p. 24 [citing 3 Tr 91]. Based upon both Mr. Ackerman's testimony and the prior finding by the Commission, the utility asserts that "the same result should be reached in this proceeding." Id., p. 25.

Again, the ALJ does not find WEPCo's arguments persuasive. It appears that the Company's position on this matter is based on the mistaken belief that by removing all of the Wisconsin-related deferred assets from the Michigan-focused working capital calculation, the utility likewise removed all benefits associated with the Wisconsin-based income tax deferrals from the capital structure. See, e.g., 3 Tr 90. However, as correctly noted by the Staff, "the comparison of working capital balances to . . . capital structure balances" cited by the Company does not fully justify removing from WEPCo's capital structure "the only component that reduces the Wisconsin portion" of the balances included therein. Staff's initial brief, p. 8. As pointed out by Ms. Bankapur:

> All [of the utility's] other capital structure balances are based on total company amounts. Since the Company presents total company amounts for all other components of the capital structure, it should do the same for [DIT]. The determination of the overall cost of capital requires that each capital balance be calculated consistently in order to arrive at an accurate overall cost of capital.

3 Tr 494. The need for a consistent analysis cited in Ms. Bankapur's testimony does, in the eyes of the ALJ, constitute an adequate basis for requiring every component of the Company's capital structure to reflect balances based on a total company basis. The ALJ therefore finds that the 13-month average DIT balance proposed by the Staff for use in developing the Company's total capital structure (specifically, $1,166,152,184) should be adopted for use in this case.

B. Cost of Debt

1. Long-Term Debt

Based on analyses provided by Mr. Ackerman, WEPCo projected its long-term debt cost to be 5.76%. See, Exhibit A-4, Schedules D1 and D2. Witness for both the Staff and the Mines recommended reducing that figure based on the results of a $300 million bond issuance that took place during September of 2011, as well as a planned issuance of another $300 million of bonds in May of 2012. Specifically, these witnesses noted that, although the Company expected both issuances to occur at a cost rate of 6.00%, the first bond placement came in at only 2.95%. See, Exhibit MIN-4. As for the 2012 issuance, the Staff's witness estimated a basic rate of 3.43%, and added a spread of 130 basis points, arriving at 4.73%, which the Staff contends is "current and reflective of declining rates in the financial markets." Staff's initial brief, p. 10 [citing 3 Tr 495]. For their part, the Mines relied on testimony from Mr. Gorman to the effect that the 2012 bond placement would cost approximately 5.01%, consisting of "the most recent quarter's 'A' rated utility bond yield" plus "a 20 basis point adjustment." 3 Tr 333.

Based on their respective witnesses' analysis, the Staff recommends adopting an overall long-term debt rate of 5.31%, whereas the Mines suggest using 5.28%. The utility asserts, both in its initial and reply briefs, that the Staff's proposed overall long-term debt rate is the more reasonable of the two and should be adopted, largely because "Mr. Gorman's calculation does not include a reasonable basis point spread." WEPCo's initial brief, at p. 25; WEPCo's reply brief, p. 7.

The ALJ agrees with that assertion. The mere 20 basis point adjustment employed by Mr. Gorman with respect to the projected 2012 bond issuance does not appear adequate. As a result, the ALJ finds the analysis presented by the Staff to be the most persuasive and well supported, and thus recommends that the Commission adopt, for purposes of this proceeding, the overall long-term cost estimate of 5.31%.

2. Short-Term Debt

As another input in calculating its rate of return, WEPCo's filing included a projected short-term debt cost of 3.50%, which its witness based upon an estimated commercial paper rate of 2.90% plus a 0.60% upward adjustment to reflect potential issuance costs. See, Exhibit A-4, Schedules D1 and D3. As for the Staff, it proposed a short-term debt cost of 1.46%, which its witness--Ms. Bankapur--based on a more recent estimate of commercial paper rates published by Global Insights for use in 2012, plus the Company's estimated insurance cost figure. See, 3 Tr 496. Finally, the Mines suggested using the projected London Interbank Offered Rate (LIBOR) rate of 0.40%, plus the 0.60% issuance cost adjustment, for a total short-term debt cost of 1.00%. See, 3 Tr 332.

As it did with regard to the long-term debt rate to use in this case, WEPCo indicated during the briefing stage of the proceedings that it was now supporting the Staff's estimated cost figure as opposed to those offered by either itself or the Mines. See, WEPCo's initial brief, p. 26; WEPCo's reply brief, p. 7.

Again, the ALJ agrees with the Staff and the Company that the testimony offered by Ms. Bankapur is more persuasive than that provided by either of the other witnesses who addressed the matter of short-term debt costs. As a result, the ALJ concludes that the Staff's proposed rate of 1.46% should be adopted for use by the Commission in computing the Company's cost of capital for the 2012 test year.

C. Cost of Common Equity

A utility's cost of common equity is the return that investors expect, or--more accurately--require, in order to provide the utility with capital for use in its various operations. The cost of this capital essentially represents an opportunity cost; in order to induce investors to purchase common stock or bonds offered by the utility in question, there must be the prospect of receiving earnings that are sufficient to make the investment attractive when compared to other investment opportunities.

When a utility stands alone and its common stock is publicly traded, direct approaches can be applied to accurately estimate a fair rate of return on the utility's common equity. However, the process becomes more complicated when the utility is a subsidiary of a holding company, as is the case with WEPCo. Because the stock of a subsidiary is not publicly traded, expert witnesses are forced to resort to indirect or proxy approaches to estimate the utility's cost of common equity. In the present proceeding, four witnesses took on some or all of this task, two on behalf of WEPCo, and one each on behalf of the Staff and the Mines.

The utility's primary witness concerning this issue, Mr. Ackerman, as well as those sponsored by the Staff and the Mines, namely Ms. Sandhu and Mr. Gorman, respectively, relied on a combination of analyses--including the Discounted Cash Flow [DCF] analysis, Capital Asset Pricing Model [CAPM], Empirical Capital Asset Pricing Model [ECAPM], and Risk Premium Model [RPM]--in developing their specific recommendations, and applied these analyses to a group of proxy entities which they felt were comparable to WEPCo. Where the presentations of these witnesses differed were: (1) the specific criteria that each used in selecting the particular entities that made up their various proxy groups; (2) adjustments that they felt were necessary to make to the previously-mentioned analyses or models; (3) the overall weight to be given to each of the outputs from those various formulae in developing their final recommendations for the return on common equity to be established for use in this case; and (4) the need to consider other factors in selecting a specific rate of return figure from within the range of results provided by their various models.

Based on the range of midpoint results arising from his various analyses (which ran “from 9.79% to 12.51%, with a median of 10.23% and a midpoint of 11.15%”), WEPCo’s witness concluded that the most appropriate rate of return on common equity to be authorized in this case should be 10.40%, or 150 basis points above the utility’s existing rate of 10.25%. WEPCo’s initial brief, p. 27 [citing 3 Tr 84]. As for the results arising from Ms. Sandhu’s analysis, they ranged from 9.85% to 10.25%. Although she recommended a rate of return nearer the low end of that range (namely, 9.95%), she explained that her bases for doing so were that (1) the common equity ratio in WEPCo’s permanent capital structure was significantly higher than that reflected in her proxy group, thus making it less risky from an investment standpoint, and (2) the Company as a whole has a lower financial risk than most members of her proxy group. See, 3 Tr 562-563. For his part, the Mines’ witness, Mr. Gorman, testified that his analyses served to support a final rate of return on common equity of 9.50%.[9] 3 Tr 333. Finally, by way of rebuttal testimony, the Company’s other witness on this issue, Ann E. Bulkley, a consultant employed by Concentric Energy Advisors, addressed alleged errors in--and her recommended adjustments to--the various inputs, methodologies, and conclusions of both Ms. Sandhu and Mr. Gorman. See, 3 Tr 154-155.

[9] Although neither offered their own testimony on this matter, both Verso and LPC support adoption of the figure proposed by the Mines’ witness, which is the lowest of the three discussed above. These parties’ support for the lowest rate of return figure proposed in this proceeding is based, in great part, on the fact that “recent increases in rates authorized by this Commission” would--assuming approval of WEPCo’s current request--result in “an increase in rates of approximately 55% in the past five years, and 33% in just the past three years.” Verso’s reply brief, p. 6 [citing LPC’s initial brief, p. 1].

Regarding what cost level should be assigned to common equity in this proceeding, the ALJ concludes that both the Staff's range and its specifically proposed percentage is the most reasonable estimate to use in establishing the rate of return on common equity for WEPCo, at least based on a projected 2012 test year. This conclusion is based primarily on two factors.

First, it strikes the ALJ that the proxy group used by the Staff is clearly the most representative of utilities like WEPCo, and thus provides cost data that is both more objective and realistic than that suggested by other parties to this proceeding. As a result, and notwithstanding attacks and proposed adjustments advocated by either the Company or the Mines, the ALJ finds that the cost range the Staff's witness suggested (namely, 9.85% to 10.25%) constitutes the best estimate of the utility's actual cost of common equity.

Second, with regard to the Staff's suggestion to establish a figure nearer the low end of its proposed range (specifically, 9.95%) for use in computing WEPCo's overall cost of capital, the ALJ again finds that this level best coincides with the totality of the record. Notwithstanding the Company's claim that the Staff's figure is too low, as well as assertions by the Mines, Verso, and LPC to the effect that 9.95% is an overly high rate of return for this utility, the ALJ recommends adopting that cost level. Since WEPCo's current cost of equity was approved by the Commission in the course of Case No. U-15981, both the economy in general, and--as acknowledged by each of the parties' rate of return witnesses--the ability to obtain financing overall, improved to at least some degree. More importantly, with the Commission's recent approval of the PTF leases--which include both the Port Washington Generating Station's two new gas-fired units, and (at least a majority of) the recently-completed, coal-fired generation units at ERGS--WEPCo's overall investor risk has certainly declined over the last few years. See, e.g., the Commission's May 22, 2007 order in Case No. U-15071, and its November 13, 2008 order in Case No. U-15500.

As a result of the issues addressed above, the ALJ recommends that the Staff's proposed cost of common equity--specifically, 9.95%--be adopted for use in this case, as opposed to the further-reduced 9.50% rate and significantly-increased 10.40% rate suggested by the Mines/Verso/LPC on the one hand, and the Company on the other, respectively.

D. Conclusion

Based on the discussion set forth above, the ALJ concludes that--at least for purposes of this PFD--the most reasonable overall weighted cost of capital to adopt for WEPCo is 6.25%, the calculation of which is depicted in the following chart.

Capital Structure	Amount	Percent	Cost	Weighted Cost
Long-Term Debt	$2,469,615,385	35.11%	5.31%	1.86%
Preferred Stock	$30,449,800	0.43%	4.01%	0.02%
Common Equity	$3,018,658,373	42.92%	9.95%	4.27%
Short-Term Debt	$323,302,703	4.60%	1.46%	0.07%
DIT (Net)	$1,166,152,184	16.58%	0.00%	0.00%
JDITC				
Long-Term Debt	$10,827,791	0.15%	5.31%	0.01%
Short-Term Debt	$1,417,490	0.02%	1.46%	0.00%
Preferred Stock	$133,504	0.00%	4.01%	0.00%
Common Equity	$13,235,018	0.19%	9.95%	0.02%
TOTAL	$7,033,792, 248	100.00%		6.25%

Although recognizing that the final figure may possibly need to be adjusted slightly to reflect both various changes engendered by other recommendations in the PFD and assumption made by the parties when preparing their testimony, the ALJ recommends that (barring some unforeseen error or change in circumstance) the Commission adopt this 6.25% figure as WEPCo's overall rate of return.

V.

ADJUSTED NET OPERATING INCOME

In order to determine whether a revenue deficiency or excess exists for a regulated utility like WEPCo, it is necessary to establish its adjusted net operating income (NOI) for the test year. WEPCo's adjusted NOI serves to express, at least in the present case and in the most basic terms, the difference between the Company's operating revenues and expenses for the projected test year.

A. Operating Revenues

1. Sales Revenue

The starting point for comparing a utility's operating revenues and expenses is the projection of its electric sales, as well as the total revenue level that they (and other utility activities) are expected to produce over the course of the test year. In this proceeding, WEPCo's initial filings indicated that--for the 2012 test year--its total weather-normalized sales would be 29,411,182 megawatt-hours (MWh), with the utility's Michigan-based sales accounting for 2,547,768 MWh. Of the Michigan-based electric usage, the Company further estimated that the Mines' load would constitute 2,016,825 MWh, whereas its projection of sales to other customers would likely be about 530,943 MWh. Neither the Staff nor any intervenor specifically challenged those figures. However, the Mines did (as part of their December 2011 filing) suggest the application of a lower consumption level during 2012, which was based upon their projected temporary reduction in energy usage at the Empire Mine. See, Exhibit A-62.

Because WEPCo's initial projection of both the Mines' and its other customers' load appears reasonable, and because it corresponds well with the levels of energy usage experienced over each of the last several years, the ALJ finds that the Company's initially-proposed sales figures should be adopted for use in this proceeding. In so finding, it is noted that the alternative sales level suggested by the Mines is based on what might simply serve to be an anomaly, as far as system-wide sales levels are concerned. As such, the ALJ recommends that the Commission adopt, for purposes of this proceeding, a total electric utility sales figure of $3,173,187,151 (which consists of $3,104,651,199 in "electric sales"[10] and $68,535,952 in "opportunity sales"). See, Exhibit A-3, Schedule C1.1.

2. Other Operating Revenue

WEPCo included, as part of its initial filing, a total electric utility other operating revenue estimate of $23,546,446. Exhibit A-3, Schedule C1.1, line 4. Based upon the testimony offered by Nicholas M. Revere, an Analyst in the Rates and Tariffs Section of the Commission's Regulated Energy Division, the Staff recommends increasing the Company's other operating revenue projection by $1,995,677. See, Exhibit S-3, Schedule C3. Specifically, Mr. Revere testified that: (1) "the Company's most recent audited data" for the prior three-year average of late payments revenue supports adding

[10] As shown in Exhibit S-3, Schedule C-3, which reflects the Staff's calculation of projected operating revenue for the 2012 test year, a $2,276 reduction was proffered with regard to WEPCo's overall electric sales revenue figure. However, the ALJ was unable to find any specific discussion of that proposed reduction elsewhere in either the record or the briefs. As a result, the figure recommended for adoption by the Commission does not include that proposed adjustment.

$76,398 to the utility's total company-based figure; (2) the most recently audited three-year average of "revenue associated with Hydro Camp/Coal Combustion Products" (HC/CP) necessitates "an adjustment of $103,730 to the Company's projected amount on a total company basis;" and (3) data assembled over the last three to five years indicates that the anticipated revenue from WEPCo's sale of excess coal in the utility's two-state service territory justifies increasing the total company coal sales estimate by $1,001,935 in Michigan and $813,615 for Wisconsin-based sales. 3 Tr 532-534. As reflected on Exhibit S-3, Schedule C3.1, making all of these changes would increase WEPCo's projected 2012 other operating revenue to $25,542,123. In addition, the Mines' witness, Mr. Gorman, recommended adding $2,534,400 to the Company's estimate of other operating revenue, based on the November 2011 announcement that the Michigan Department of Natural Resources (MDNR) had been authorized to purchase 2,354 acres of land from WEPCo in the Upper Peninsula for that price. See, 3 Tr 373; Exhibit MIN-47.

The Company "does not contest for purposes of this proceeding" the Staff''s proposed increases to other operating revenue relating to late payments, HC/CP, or the sale of excess coal in Michigan. WEPCo's initial brief, p. 50. Nevertheless, the utility does oppose approval of the Staff's suggested revenue increase concerning coal sales in Wisconsin, as well as the Mines' proposed increase due to the likely sale of land to the MDNR. With regard to the first area of dispute, the Company asserts that although it regularly sells coal to several customers in Michigan, it "does not normally sell, or plan to sell, coal to customers in Wisconsin" during 2012. Id., p. 51. In support of its assertion that this proposed adjustment should be rejected, WEPCo cites rebuttal testimony offered by Mr. Ackerson to the effect that:

> The Company does not purchase coal with the intent to resell to any Wisconsin entity. The Wisconsin sales over the last three years resulted from significant reductions in actual burn rates after coal had been purchased to meet our needs. We were able to sell some of that coal as part of the lowest cost alternative to reduce the temporary surplus. Our coal commitments for 2012 are currently aligned with our burn projections, and we do not expect to have surplus coal to sell, and therefore do not believe it is appropriate to reflect any Wisconsin related coal revenue.

3 Tr 96. Turning to the Mines' proposed treatment of any revenue arising from the utility's sale of land to the MDNR, WEPCo similarly relies on Mr. Ackerman's statement that:

> The land that was the subject of this sale has been recorded as a non-utility asset (Account 121) since at least 1996. For ratemaking purposes, investment in non-utility assets is excluded from rate base. The gain on the sale was approximately $2.3 million. The sale closed on December 21, 2011. [WEPCo] does not project making a similar sale of land in 2012. The proceeds from the sale are not utility revenues for ratemaking purposes and should not be added to 2012 test year revenues.

WEPCo's initial brief, p. 53 [citing 3 Tr. 101]. Based on both the above-quoted testimony and the Commission's past rulings (at least with regard to the sale of non-utility assets), the Company argues that neither of the two disputed adjustments to other operating revenue should be adopted in this case.[11]

With respect to the proposed adjustment for potential coal sales in Wisconsin, the ALJ does not find the utility's arguments persuasive. Notwithstanding WEPCo's claim that circumstances giving rise to its past coal sales in Wisconsin no longer exist, the fact of the matter is that (as reflected in the P-521 reports referred to by Mr. Revere)

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[11] For its part, Verso agrees with the Staff's proposal to increase WEPCo's revenue to reflect the average level of coal sales in Wisconsin, but--based on its reading of the prior Commission orders cited by the utility--does not support the land sale-related adjustment suggested by Mr. Gorman. See, Verso's reply brief, p. 7.

the Company has, for at least five years in a row, sold some amount of coal to various customers located in that state. See, 3 Tr 533-534. Based on WEPCo's past activities, the ALJ concludes that the most reasonable course of action is, as the Staff suggests, to simply assume that some level of surplus coal sales will be made in Wisconsin during 2012. Moreover, the ALJ likewise agrees that the best estimate of this revenue is the five-year historical average relied upon by the Staff's witness. As a result, the ALJ finds that the $813,615 increase in WEPCo's total company other operating revenue related to Wisconsin-based coal sales should be made along with the unopposed adjustments suggested by Mr. Revere. Doing so would increase the Company's other operating revenue from its as-filed figure of $23,546,446 to $25,543,123. See, Exhibit S-3, Schedule C3, line 3.

With regard to the Mines' suggestion to increase the utility's revenues to reflect its recent sale of land to the MDNR, however, the ALJ agrees with WEPCo that doing so would be inappropriate. The record indicates that the land in question has been recorded by the Company as a non-utility asset for at least the past 16 years. See, 3 Tr 101. Thus, based on the prior Commission orders cited by the utility (specifically, the July 16, 1987 order in Case No. U-7830; the May 10, 1994 order in Case No. U-10335; and the April 28, 2005 order in Case No. U-14378), the ALJ finds that the Commission should reject the Mines' proposal to reflect the $2,534,400 sales price in the calculation of WEPCo's other operating revenue.

3. Conclusion

For the above-stated reasons, the ALJ recommends adopting a 2012 total electric utility operating revenue figure for WEPCo of $3,198,729,274 (consisting of

$3,104,651,199 in retail sales, opportunity sales of $68,535,952, and other operating revenue of $25,542,123). However, in contrast to the relatively small number of disputes concerning the selection of an operating revenue figure for use in this case, numerous differences of opinion were expressed among the parties regarding the level and treatment of various operating expenses. Each of those expense-related issues is discussed below.

B. <u>Operating Expenses</u>

WEPCo's total electric utility O&M expense for the test year was listed in its filing as $2,528,065,507. Exhibit A-3, Schedule C1.1, line 18. Of that total, net projected fuel and purchased power costs were $1,165,366,780. <u>See</u>, Exhibit A-3, Schedule C4. Excluding fuel and purchase power expenses, the balance of the Company's proposed O&M expense--which is referred to in the context of this PFD as Miscellaneous O&M Expense--is $1,372,698,727. <u>See</u>, Exhibit A-3, Schedule C5, line 19.

Based on the testimony of its witnesses regarding operating expense issues, namely Mr. Birkam and Brian A. Welke, an auditor in the Revenue Requirements Section of the Commission's Regulated Energy Division, the Staff recommended no change to the utility's estimated 2012 fuel and purchased power expense. However, with regard to Miscellaneous O&M, Mr. Welke suggested making a pair of downward adjustments. The first was the removal of all costs relating to incentive compensation and executive perquisites (including performance bonuses), while the other concerned the adoption of a lower level of injuries and damages expense based upon the Staff's suggested application of a five-year historical average. Based on those two adjustments, the Staff's recommended Miscellaneous O&M expense figure totaled

$1,319,540,483 (a $53,158,244 reduction from the figure proposed by WEPCo). See, 3 Tr 584-587. The Company subsequently indicated that, "for purposes of reducing the number of contested issues with the Staff," it does not contest the Staff's proposed downward adjustments to these two projected Miscellaneous O&M expenses. WEPCo's initial brief, p. 54. None of the other parties to this case object to those adjustments.

However, based on testimony offered by their witness, Mr. Gorman, the Mines asked for several additional reductions in the overall expense levels contained in the utility's filing. These adjustments include: (1) the exclusion of all costs, both lease- and O&M expense-related, with regard to ERGS-2; (2) reductions in the payments called for under all PTF-related leases (concerning all four PWGS and ERGS units);[12] (3) the removal from rate base of all costs related to WEPCo's various RE-related activities; (4) reductions in the Company's costs incurred with regard to payroll, pensions and benefits, injuries and damages, and production maintenance; and (5) the elimination of any recovery for common board of directors expenses. See, the Mines' initial brief, pp. 14-29, and 35-41. While a specific breakout of the overall impact these adjustments will have on WEPCo's complete revenue structure is not readily apparent from the record, suffice it to say that they go a long way toward supporting the Mines' claim that the Company "will actually experience a substantial revenue *surplus* of at least $16.8 million in 2012." Id., p. 4 (emphasis in original).

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[12] PTF is a large investment program, first announced in September 2000, designed to expand WEPCo's existing power plants to improve efficiency and reduce emissions, and to upgrade WEPCo's distribution system. The PTF program includes, among other things, the construction of two new gas-fired generating units at the Port Washington Generating Station (PWGS), as well as the construction of two new coal-fired generating units at the Elm Road facility, designated as ERGS-1 and EGRS-2. These plants, approved by the PSCW after significant contested case proceedings in Wisconsin, were constructed by We Power, LLC, a WEPCo affiliate, and are leased to WEPCo for up to 30 years. See, the Commission's July 1, 2010 order in Case No. U-15981, pp. 5 and 26.

1. <u>Purchased Power and Production-Related O&M Expense</u>

Although no dispute was raised with regard to many of the specific generation-related expense levels and miscellaneous financial adjustments included in WEPCo's initial filing, the above-mentioned issues (which constitute a large portion of the Company's projected test year costs) remain to be addressed. These include matters relating to certain generating facility lease costs arising from the Company's long-standing Power PTF program, as well as expenses associated with the utility's various RE activities, among others.

a. <u>ERGS-2 Lease Costs</u>

In WEPCo's most recent general rate case proceeding, Case No. U-15981, the Company sought to recover in rates the cost of the PTF-based leases it signed with regard to both ERGS-1 and ERGS-2, with the applicable rate increase set to take effect only as each facility commenced commercial operation. In that proceeding, both the Mines and other intervenors opposed any recovery of ERGS lease costs on several bases, including claims to the effect that those generating units were not "used and useful," arguments that capacity from those facilities was not needed during the 2010 test year applied in that case, and assertions that the costs arising from these leases exceed the projected average cost of energy in the Midwest Independent System Operator (MISO) market. However, in its July 1 order, the Commission rejected these arguments, included ERGS-1 lease costs in rates, and denied the intervenors' request to make various downward adjustments to the PTF lease payments. Specifically, the Commission stated that:

By far the most contentious issue in this case centers on the appropriate ratemaking treatment of the ERGS units. On the one hand, WEPCo argues that all expenses associated with both ERGS-1 and ERGS-2 should be included in rates because the decision to build and lease the plants was reasonable and prudent at the time the decision was made.[13] Diametrically opposed are the Mines and LPC, who argue that because WEPCo currently has significant excess capacity, ERGS-1 and ERGS-2 are not used and useful in the provision of utility service and that all costs associated with these units should be entirely excluded from rates charged to Michigan customers. Considering the removal of ERGS costs and other adjustments to WEPCo's filing, the Mines calculated a revenue excess of $17.9 million.

The Staff takes a position in the middle, arguing that the expenses associated with ERGS-1 are properly recognized for the (2010) test year, but because the date of commercial operation of ERGS-2 is uncertain, none of the costs associated with ERGS-2 should be incorporated into WEPCo's retail rates at this time. With other adjustments, the Staff calculated a revenue deficiency of $28,098,404.

The Staff argued that the ERGS units will benefit WEPCo's future customers as WEPCo's sales increase. The Staff posited that if WEPCo releases too much of its capacity now, and the Company does not have enough capacity to supply its load when the economy rebounds, WEPCo's customers will be forced to buy energy from the market at higher rates.

* * * * *

As discussed (where necessary) in more detail below, the Commission finds that the Staff's recommended approach to addressing the concerns regarding ERGS-1 and ERGS-2 is the most reasonable. The Commission agrees that it is improper to use hindsight to second guess WEPCo's decision in 2002 to add capacity to its generating system; at that time, it reasonably appeared that WEPCo would need ERGS baseload capacity by 2009 and 2010, and the severe economic downturn in 2008 was not foreseeable. However, the Commission agrees that because the date when ERGS-2 will begin commercial operation is uncertain, it is reasonable to exclude the lease associated with that unit from the [2010] test year.

July 1 order, pp. 5-7.

[13] It appears that, following receipt of approval by the PSCW, construction of ERGS-1 and ERGS-2 commenced in 2002 through 2004. See, July 1 order, p. 5.

Based on the above-quoted language, WEPCo contends that the July 1 order expressed the clear intent to (1) include all ERGS-1 lease costs in the Company's rates from that point forward, and (2) simply refrain from doing the same for ERGS-2's lease expenses until that facility commenced commercial operation. See, WEPCo's initial brief, p. 58. Moreover, the utility points out that ERGS-2 actually began operating on a commercial basis in January 2011. See, Id. Since that time, the Company goes on to note, it "has been obligated to make lease payments for [ERGS-2], and Michigan customers have received their allocated share of energy" from the facility without being required to reimburse the utility for either "the allocated portion of [that unit's] lease or O&M expense." Id. As such, WEPCo argues that the ratemaking principles recognized and applied by the Commission in Case No. U-15981 (namely, recognizing the right of a utility to recover reasonably and prudently incurred costs, and that prudency must be determined at the time that the decision is made), as well as the factual findings reached in the July 1 order (to the effect that the decisions made as far back as ten years ago to construct the ERGS units and enter into the leases regarding their usage were reasonable and prudent), support full recovery of the ERGS-2 lease costs at this time. See, Id.

The Staff agrees with WEPCo, and supports authorizing the recovery of the costs associated with ERGS-2. Although conceding that--at least under the current economic conditions--ERGS-1 and ERGS-2 together provide more generating capacity than the Company may need at times, the Staff goes on to point out that two of the utility's long-term capacity purchases (representing 334 MW and 168 MW of energy) expire in 2011 and 2012, respectively. See, Staff's reply brief, pp. 12-14. Moreover, the Staff points to the Commission's ruling in the July 1 order that WEPCo's decades-old decision to build the various PTF facilities "was reasonable at its inception and remains a valid basis for continuing to allow recovery in rates of current lease payments even if today, the facilities produce excess capacity." Id., p. 15.

In contrast, the Mines propose "excluding all [ERGS-2] lease payment costs as well as all deferral amortization costs for pre in-service ERGS lease payments from rate base," which they contend will reduce WEPCo's alleged 2012 revenue deficiency by approximately $8.3 million. Mines' initial brief, p. 22. In support of this proposal, the Mines assert that ERGS-2 would not be "used and useful" during the 2012 test year because it, like ERGS-1, would constitute excess capacity. Id., p. 15. Although noting that "the Commission made a legal determination" in the July 1 order "that 'the used and useful' doctrine was irrelevant with respect to utility expenses" (as opposed to potential additions to rate base), the Mines claim that "the Commission's legal conclusion was erroneous." Id. Moreover, they argue that because the terms and conditions of the lease agreement covering this facility "are not reasonable and were not reasonable at the time that the lease was executed," the ERGS-2 expenses "should not be included in WEPCo's 2012 cost of service," and that allowing the Company to do so would let it recover more costs related to this generating unit "than it would have been permitted to recover had [the utility] owned, rather than leased, the facility." Id., pp. 15-16.

For its part, LPC likewise renews its claims from Case No. U-15981 to the effect that neither ERGS-1 nor ERGS-2 are used and useful, and thus none of the costs arising from their respective leases should be recovered from Michigan ratepayers. See, LPC's initial brief, pp. 3-4. As for Verso, it--like the Mines and LPC--"believes that the Commission's prior decision was erroneous, and that "the Mines' position [regarding ERGS lease costs] should be adopted by the Commission in this case going forward." Verso's reply brief, p. 12.

The ALJ disagrees with the basic premise underlying the positions taken by the Mines, LPC, and Verso, namely that the Commission's decision in the July 1 order was patently erroneous. On pages 5-7, 9-11, and 26-31 of that decision, the Commission went to great lengths to describe why, based on the circumstances presented, it was more appropriate to essentially apply a "reasonable and prudent" standard when considering ERGS lease costs as opposed to employing the "used and useful" test advocated by the intervenors. As specifically noted by the Commission, there was no proposal to include these generating units in rate base, and thus allow recovery both on and of the investment made in those facilities. Rather, as correctly noted by the Staff in Case No. U-15981, all WEPCo sought in that proceeding (as well as in this case) was to recover the lease payments on the ERGS units, amortization of the lease payments, and any carrying costs associated with the lease payments. See, July 1 order, p. 10. Thus, treating these leases in the same manner as any other long-term power purchase agreement--specifically, by applying the reasonable and prudent standard--makes good sense.

Moreover, the Mines' request to strictly evaluate these long-standing lease agreements in terms of today's market conditions seems (as the July 1 order essentially concluded) inequitable at best, and brazenly opportunistic at worst. Testimony provided by WEPCo's Manager of Fuel Cost Planning, Mary L Wolter (found at 3 Tr 225-248), as well as information set forth on Exhibits A-53 through A-56, describes in detail both the circumstances facing the Company at the time it decided to enter into the ERGS leases, and the extensive hearings conducted and actions undertaken (by the utility, consumer advocates, and regulators in Wisconsin) to ensure that WEPCo's decision to lease ERGS-2 was the most cost-effective means of satisfying the then-projected customer demand levels, while concurrently ensuring that the proposed PTF lease provisions--including the presumed rate of return, capital structure, etc., used in evaluating those provisions--were reasonable. In contrast, the information provided by the Mines' witness, Mr. Gorman, neither addressed the circumstances existing at the time that those decisions were made nor identified any unreasonableness or imprudence on the part of the Company.

Finally, and as correctly noted by the utility, "the only reason that [the ERGS-2] lease costs were not included in the rates approved in the July 1 order . . . was the uncertainty of whether [it] would commence commercial operation" during the 2010 test year relied upon in that proceeding. WEPCo's initial brief, p. 59. As the Company went on to point out, "that uncertainty was eliminated" for purposes of the present proceeding when ERGS-2 began commercial operation in January 2011, 11 full months prior to the test year selected for use in this case. Id. Thus, because the ratemaking principles applied and findings made by the Commission in the July 1 order would appear to apply equally to the ERGS-2 unit as to the ERGS-1 facility, the ALJ finds that the Commission should authorize recovery of all ERGS-2 lease expenses in the context of this case.

b. PTF Lease Provisions

As briefly alluded to above, and as also occurred and was addressed in the context of Case No. U-15981, several objections have been raised regarding WEPCo's proposal to have the Commission effectively adopt the earlier findings of the PSCW concerning the PTF leases and to approve recovery of all the expenses associated with the PWGS and ERGS facilities. The Mines and LPC argue here, as they did in that proceeding, that--if the financial effects of those leases are included at all as part of the Company's 2012 test year expenses--the Commission should only authorize recovery of reasonable costs, as opposed to those proposed by the utility. See, i.e., Mines' initial brief, p. 22. Specifically, these two intervenors contend that because the leases were arranged as part of an affiliate transaction, a higher level of scrutiny should be applied, thus ensuring that they do not provide "unreasonable or excessive compensation" to WEPCo's affiliate, We Power. Based in large part on testimony provided by the Mines' witness, Mr. Gorman, these parties assert (as they did in Case No. U-15981) that the capital structure, rate of return on common equity, cost of long term debt, length of the leases, and capitalized costs of deferred lease pre-payments relied upon when developing the overall cost of the PTF leases are not realistic when compared to current circumstances, and that the recoverable cost of the leases must be reduced significantly to reflect that fact. See, Mines' initial brief, pp. 23-27; LPC's initial brief, pp. 4-5.

The ALJ does not find the assertions offered by the Mines and LPC persuasive, and instead concludes that the Commission should accept the cost levels included in the PTF leases as stated in those agreements. To impose the significantly reduced expense levels advocated by these intervenors (which are based almost exclusively on the lingering effects of the dramatic and unforeseen economic downturn of 2008) strikes the ALJ as patently unfair. This conclusion is wholly consistent with the findings set forth in the July 1 order, where it was specifically noted that:

> With regard to the PWGS lease, the Commission observes that the Mines were parties to the settlement agreement approved on May 22, 2007 in Case No. U-15071, and that the Mines and LPC were parties to the settlement agreement approved in the November 13, 2008 order in Case No. U-15500. In both of these settlement agreements, the parties agreed that the increased rates included lease payments and prepayments for the PWGS facility. Thus, the appropriate time to have objected to the terms of the PWGS lease was in those proceedings.

July 1 order, p. 29. As for the lease terms (and their corresponding costs) for ERGS-1 and ERGS-2, the ALJ likewise agrees with the Commission's earlier finding that when evaluating factors like capital structure, return on equity, debt cost rates, lease length, and treatment of capitalized costs related to pre-payments:

> [T]he appropriate inquiry is to the market conditions and risks at the time the leases were executed in 2002 and 2004, and that some consideration should be given as well to the fact that over the course of 30 years, circumstances and costs will inevitably change. As WEPCo points out, the Company appeared to be facing a critical need for additional capacity at the time the leases were signed. In addition to the existing overall market conditions, WEPCo asserts that a higher return was required to assure that the ERGS units were actually built. The Commission therefore finds that the levelized after tax costs contained in the ERGS leases are reasonable.

Id., p. 30.

As a result, the ALJ recommends that the Commission again reject the proposals offered by the Mines and LPC to essentially alter the PTF lease provisions, and instead authorize the recovery of all expenses associated with those leases.

c. ERGS-1 Deferred Pre-Lease Payments

Based on the terms of the PTF generating plant leases, WEPCo (as the lessee) was required to make pre-lease (i.e., construction assistance) payments designed to partially offset the lessor's cost of financing the facilities' construction. By way of its previous orders, the Commission approved the deferral of those pre-lease expenses and allowed for their recovery by amortization over the term of each respective facility's lease once the generating unit had commenced commercial operation. With regard to ERGS-1, the Commission allowed for the use of such regulatory treatment regarding all pre-lease costs arising from the unit's construction until the July 1 order was issued in Case U-15981, at which point the Company was authorized to begin recovering via rates (again, over the 30-year term of the lease) all previously-deferred ERGS-1 pre-lease costs.

As noted by several of the parties, ERGS-1 was beset with numerous operational issues during the first eight months following its formally-announced commercial operation date of February 2, 2010. See, Staff's initial brief, p. 42. Some of these issues--including a pump vibration and various items set forth on an "open punch list" of maintenance matters to be attended to in the near future--appear to have been known by WEPCo when the unit went on line, although apparently not by the other parties to Case No. U-15981. See, i.e., Exhibit S-6, Schedules G2 and G3.

Due to this facility's less-than-stellar performance, the Staff proposes that "the Commission establish a regulatory liability of $6.7 million," and further suggests that "the amortization of the regulatory liability match the amortization of the [ERGS-1] lease pre-payments until the amount of the regulatory liability has been reduced to $0." Staff's initial brief, p. 46. According to the Staff, its recommendation essentially represents "a deferred accounting adjustment based on information that was unknown to the parties or the Commission" when the July 1 order was issued. Id. The Staff goes on to assert that such treatment is consistent with legal precedent to the effect that, when the costs upon which rates are based are shown to have been inaccurate, "the previously set rates cannot be changed to correct for the error; the only step that the [Commission] can take is to prospectively revise rates in an effort to set more appropriate rates." Id., pp. 46-47 [citing Attorney General v. Public Service Comm, 262 Mich App 649, 656 (2004)]. Thus, the Staff concludes, it is within the Commission's authority to establish more appropriate rates for WEPCo by adopting the Staff's proposed adjustment. Both LPC and the Mines support that conclusion. See, LPC's reply brief, pp. 5-6; Mines' reply brief, p. 14-17.

Nevertheless, the ALJ finds that the above-described conclusions (as well as the Staff's proposal) must be rejected. As attractive as the Staff's suggestion might appear, the ALJ believes that it should not be adopted for the following three reasons.

First, as was noted in the July 1 order, WEPCo has the right to rates designed to collect all reasonably and prudently incurred PTF lease expenses. This fundamental ratemaking principle applies as well to the recovery of deferred ERGS-1 pre-lease costs. Due to the lack of record evidence showing that some unreasonable and imprudent action by the Company either caused or prolonged the outages experienced during 2010, Staff's currently-proposed disallowance essentially seeks to deny recovery of the deferred pre-lease expenses in question solely on the grounds of historical plant availability and usage. Granting such a disallowance would, as correctly noted by the utility, "be contrary to the reasonable and prudent ratemaking standard" that the July 1 order found to fully support the recovery of all ERGS-1 lease expenses. WEPCo's initial brief, p. 78.

Second, the Staff's reliance on Attorney General v PSC as support for its claim that adopting the $6.7 Million disallowance would not conflict with the rule against retroactive ratemaking is clearly in error. The Appeal's Court statement in that case (to the effect that if previous rates were too high, the only remedy would be to prospectively revise rates in an effort to set more appropriate rates) is most logically read as recognizing that any error in establishing past rates--either by setting them too high or too low--is, in common parlance, water under the bridge. As correctly noted by the Company, "it is an unsupportable misconstruction of the Court's statement" for the Staff to assert that "the reference to 'more appropriate rates' refers to the rates which disallow recovery of current costs in a attempt to recoup any excess" arising from previous Commission-approved rates. WEPCo's reply brief, p. 24.

Third and finally, the evidence received in this proceeding fails to identify any particular actions taken by the Company concerning the commencement of commercial operation and the actual turn-over of ERGS-1 from WE Power to WEPCo that were either unreasonable or imprudent. Moreover, and as both noted above and mentioned in the July 1 order, the PSCW conducted extensive proceedings involving a large number (as well as a wide spectrum) of stakeholders, all in an attempt to ensure that both the scope of the PTF program and the specific terms of any resulting leases were reasonable. This was particularly the case, it appears, with regard to those leases' facility-completion, pre-operation testing, and generating unit turn-over provisions, as fully described in testimony provided by no fewer than three of the utility's witnesses. <u>See</u>, <u>i.e.</u>, 3 Tr 212-215, 3 Tr 227-230, and 3 Tr 256-258.

For all of these reasons, the ALJ finds that the Staff's proposed treatment of ERGS-1 deferred pre-lease payments should be rejected, and that the previously-anticipated recovery should proceed as planned. It is therefore recommended that the Commission continue authorizing the recovery of those expenses.

d. RE-Related Costs

In its initial filing, WEPCo included--as a part of its proposed 2012 revenue deficiency--an analysis of the Michigan-allocated portion of its various "hydro-generation projects, the Blue Sky/Green Field (BS/GF) wind project, and RE Purchased Power Agreements (PPAs), other than [the Company's] PPA with Barton."[14] WEPCo's initial brief, p. 96. Based on that filing, the utility's "proposed base rate adjusted gross revenue deficiency included an adjustment of $3,743,142," which was intended to remove the Michigan-allocated portion of "the cost of the Barton PPA and Glacier Hills wind project (Glacier Hills) from the revenue deficiency calculated in this case." Id. However, WEPCo went on to note that it was subsequently determined that the Barton PPA "does not qualify as RE" under Michigan's Clean, Renewable, and Efficient Energy Act of 2008, 208 PA 295, MCL 460.1000, et seq. (Act 295), meaning that its costs should be treated differently than those related to Glacier Hills. Id., p. 97.

The Staff agreed, in large part, with the utility's initially-proposed treatment of its RE-related costs. Nevertheless, "in response to an update Staff requested from the Company," the Staff's witness on this issue--Mr. Birkam--proposed an RE adjustment of $60,890,000 on a total electric utility basis, which resulted in a suggested $4,129,051 adjustment for the Company's Michigan-based revenue calculation. Staff's initial brief,

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[14] WEPCo is required by Wisconsin law to satisfy a renewable portfolio standard (RPS) which includes electric generation from Company-owned wind, solar, hydro, and biomass facilities, or from PPAs providing electricity from such sources. Provisions of that law require utilities regulated by the PSCW to hit certain benchmarks regarding their level of renewable-based electric generation, which are computed as a percent of their respective Wisconsin electricity sales. Pursuant to that law, WEPCo is required to achieve an RE level of 8.27% of its Wisconsin-based retail sales by 2015.

p. 25 [citing 3 Tr 503-504]. According to the Staff, this $4,129,051 adjustment "removes the Act 295 qualifying renewable generation from rates." Id. Assuming its above-mentioned adjustment is made [which, it appears, expands the Glacier Hills adjustment, while adopting the utility's figure regarding the removal of Barton PPA costs] the Staff supports WEPCo's proposed level of recoverable RE expenses.

In contrast, both the Mines and LPC claim that none of the utility's incremental RPS costs should be allocated to its Michigan ratepayers. According to the Mines, it is "patently unjust and unreasonable" for the Company's Michigan-based customers to exclusively pay for WEPCo's Act 295-related (e.g., Michigan's Legislatively-demanded) incremental RE costs, while also being required to pay a portion of the utility's PSCW-mandated RE-costs. Mines' initial brief, p. 45. Moreover, these parties assert, Michigan ratepayers should not pay for any incremental Wisconsin-related RPS costs at all, due to the fact that WEPCo currently generates and/or purchases more RE than needed to meet the level required under its PSCW-monitored, system-wide RPS. See, Id., 44-47. They therefore contend that, based on the treatment of WEPCo's RE-related expense in the July 1 order--wherein the Commission rejected the Company's proposed cost recovery--all Wisconsin-related RE expense should be excluded from this proceeding, thus reducing the utility's Michigan retail cost of service requirement by $5.048 million. See, Id., p. 49; LPC's initial brief, pp. 6-7.

For its part, Verso supports the Staff's recalculation of the Glacier Hills deduction (which WEPCo itself does not now challenge), agrees with both the Company and the Staff that all Barton PPA costs should be removed from consideration because they do not actually constitute RE-related expenses, and concludes that--as asserted by the utility--the additional adjustments requested by the Mines and LPC were already fully addressed by the Commission in Case No. U-15664-R and, thus, should be rejected in the context of this proceeding.

The ALJ agrees with Verso, the Staff, and WEPCo, and finds that the only revision that need be made to the Company's base level of RE cost recovery (at least so far as those costs are to be collected from the utility's Michigan-based customers) is the $4,129,051 adjustment proposed by the Staff. Notwithstanding the rejection of various RE cost recovery requests in the context of WEPCo's prior rate case, the Staff correctly notes that the Commission has effectively reversed position on this issue. For example, in the utility's most recent PSCR reconciliation case order, the Commission--when reviewing the issue of how to best allocate WEPCo's total RE-related costs to the Company's Michigan customers--stated that:

> The Commission continues to believe that use of the system-wide average basis for determining costs is beneficial to Michigan customers, and [thus] authorizes inclusion of [Wisconsin RPS] compliance costs in the PSCR, including the amounts considered to be in excess of what was needed to comply with the [Wisconsin RPS] in 2009.
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> * * * * *
>
> With the exception of two new contracts, all of the [RE agreements] presented by WEPCo were previously approved by the Commission, and the ALJ found the two new contracts to be reasonable. PFD, p. 44. The rate impact limits of the Michigan [RE] standards do not apply to "costs approved for recovery by the commission other than as provided in [Act 295]." MCL 460.1045(3). [Wisconsin RPS] compliance costs were included in the 2008 reconciliation and in the 2009 plan case. The fact that WEPCo bought more [RE] than the bare minimum required for the [Wisconsin RPS] does not mean that the purchases were unreasonable.

December 6, 2011 order in Case No. U-15664-R, at p. 10. Because Michigan-based customers will have the benefit of the system-wide allocation of WEPCo's RE credits, thus automatically pushing them to the 8.27% RE level by 2015, the incremental costs necessary to attain the 10% RE standard imposed by Act 295 in Michigan are vastly reduced from what they otherwise would have been. This financial benefit, as recognized by the Commission through its recent order in Case No. U-15664-R, more than justifies the inclusion of those RE-related expenses in the calculation of the Company's cost of service as it applies to its Michigan ratepayers.

As a result, the ALJ finds that the Staff's proposed adjustment to the Company's as-filed RE-related expenses should be adopted, and that the Commission should reject the additional cost reductions offered by the Mines and LPC.

2. Miscellaneous O&M Expense

As mentioned earlier, the Staff proposed, and the utility ultimately accepted, a total electric company O&M expense reduction in the amount of $53,158,244 relating to (1) incentive compensation and executive perquisites (including various performance bonuses),[15] on the one hand, and (2) injuries and damages expense, on the other. Still, four other areas of miscellaneous O&M expense remain in dispute. These concern WEPCo's payroll expense, employee pension and benefits expense, other production expense, and the utility's assigned portion of its parent company's Board of Directors expense. Each of these disputed issues is addressed below.

a. Payroll Expense

By way of its application, the Company based its projected payroll expenses for the test year upon: (1) an estimated 4,879 full-time equivalent (FTE) positions, as well

[15] LPC also specifically supported excluding each of these executive-focused expenses. See, LPC's reply brief, p. 7

as (2) projected wage and salary increases for 2011 and 2012 of 5% for executives, 3.5% for management employees, and 3% for non-union and various not-under-contract workers. See, 3 Tr 45 and 366.

The Mines, in contrast, contend that WEPCo's total electric utility payroll expense for the 2012 test year should be (1) reduced by $13.2 million to reflect only those FTE positions that were actually filled during 2010, namely, 4,647 positions, and (2) reduced by an additional $6.1 million, based on their proposal to cap all increases in wages and salaries for employees not currently guaranteed (via contract or otherwise) to 1.5% for 2011 and 2012. Verso, the only other party to directly weigh in on these two issues, supports the Mines' proposals with regard to both the $13.2 million decrease concerning the number of likely FTEs in 2012, and the $6.1 million reduction gleaned from capping all wage increases (beyond those already guaranteed by contract) at 1.5% for the 2012 test year. See, Verso's reply brief, pp. 9-10.

The ALJ agrees with the assertions offered by the Mines and Verso on this issue, and thus recommends that the Commission make the suggested total $19.3 million downward adjustment to the Company's overall payroll expense (on a total electric utility basis).

Although the ALJ generally supports WEPCo's plan to shift work from outside contractors to new in-house employees, as proposed by Mr. Ackerman, and further believes that increasing the Company's use of such employees (whose training and conduct are more easily monitored, controlled, and directed by the utility) could ultimately prove beneficial to both the Company and its customers, past actions by WEPCo conflict with its projections regarding future employment levels. As noted by the Mines, and reflected on Exhibits MIN-37 and MIN-38, year-end actual employment numbers for the Company were--on average--nearly 300 FTEs less than were budgeted. See, Mines' initial brief, pp. 37-38. Should the utility actually follow through on its proposal to increase the overall level of FTEs within its operations during 2012, the Commission can subsequently (and based on more accurate historical data) accommodate the requested cost increase suggested by the utility in the context of its next general rate case.

Furthermore, as far as the projected level of wage and salary increases proposed by the Company, the lower figure proposed by the Mines' witness, Mr. Gorman, appears to more closely correspond to both the expected economic conditions and overall level of inflation assumed by a majority of the parties to this proceeding than does WEPCo's suggested increases, particularly with regard to management and executive employee wages and salaries (which were pegged at 3.5% and 5%, respectively). As noted by Mr. Gorman and reflected on Exhibit MIN-42, part of a report issued by the PSCW Staff on July 19, 2011, recommended limiting wage increases for each of the three employee groups at issue to 1.5% in both 2011 and 2012. See, 3 Tr 367. Absent a clear showing regarding why numerous wage and salary levels should increase at rates greater than the reasonably-expected level of inflation assumed for most other areas of WEPCo's expenses, the ALJ finds that that the lower rate of increase suggested by the Mines and supported by Verso should be adopted instead.

For the above-stated reasons, the ALJ finds that, with regard to payroll expense, the Company's estimated cost of FTE positions should be reduced by $13.2 million, and its proposed wage and salary increase expense should be reduced by $6.1 million, for a total electric utility adjustment of $19.3 million for the 2012 test year.

b. Employee Pension and Benefits Expense

WEPCo's projected 2012 test year total electric utility pension and benefits expense is $91,610,004. See, Exhibit A-3, Schedule C5, line 12. The Mines, however, advocate reducing that figure by $8.1 million, largely because making such a reduction would correspond with its lower number of FTEs, as discussed in the preceding section. See, Mines' initial brief, pp. 39-40. Verso supports making this downward adjustment in the Company's total pension and benefits expense. See, Verso's reply brief, p. 10.

The utility responds by asserting that, because the proposed reduction in pension and benefits expense is directly tied to the lower number of FTEs that Mr. Gorman assumes it will actually have during 2012, and because WEPCo's estimate of test year FTEs is superior to his proposed figure, this adjustment must be rejected. See, WEPCo's initial brief, p. 108. This would, the Company notes, match what the PSCW did in Wisconsin last year in response to a similar suggestion. See, Id., pp. 108-109. In addition, the utility asserts that although the Mines' witness, Mr. Gorman, attempts to justify his proposed reduction by simply pointing to "the variance between projected and actual expense levels for 2010," no evidence was offered in this proceeding to the effect that WEPCo's "projection of 2010 expense levels was unreasonable." Id., p. 109. The Company therefore contends that its figure is superior to that proposed by Mr. Gorman, and that his recommended cost reduction should not be adopted.

The ALJ does not find the utility's contentions persuasive. First and foremost, because this PFD recommends adopting the FTE figure (and its corresponding expense level) proposed by the Mines and Verso, logic requires making a similar reduction in overall employee pension and benefits expense. Moreover, no matter how one chooses to view the matter, the record clearly shows that although WEPCo projected a 2010 pension and benefits expense of $98.4 million, its actual total of all such expenses for that year was only $76.8 million, or $21.6 million below the estimated level. See, Mines' initial brief, p. 39, citing Exhibit MIN-41. If and when the Company actually fills the positions it claims are necessary to operate efficiently, the Commission could revisit this issue. Until then, the ALJ finds that (based on the continued difference between the utility's projected FTE levels/benefit costs and the actual figures) a conservative approach is preferable.

In light of the above-stated finding, the ALJ recommends that the Commission adopt the $8.1 million downward adjustment to employee pension and benefits expense suggested by the Mines and supported by Verso.

c. Other Production Expense

With regard to its other production expense, which largely consists of generation plant maintenance costs, WEPCo's application sought to include $626,325,575 on a total electric utility basis. See, Exhibit A-3, Schedule C1.1, line 9. The Mines and Verso propose reducing that figure by $10.1 million for the 2012 test year. See, Mines' initial brief, p. 40; Verso's reply brief, p. 10. According to the Mines, this adjustment would serve primarily to reflect the 2008 through 2010 historical average level of "non-labor steam power maintenance expenses, increased for inflation between 2010-2012, increased for additional maintenance associated with the ERGS facility, and decreased for the sale of Edgewater-5.[16]

In response to this proposed cost reduction, WEPCo points out that it was "based entirely upon the fact that such a recommendation was set forth in Exhibit MIN-36," which is a part of the PSCW Staff's July 2011 report and recommendation to the PSCW. However, as noted by the utility's witness on this issue, Mr. Ackerman:

> This adjustment was based on a 2008-2010 three-year historical average of the Company's power production expense adjusted for specific items compared to the 2012 test year estimate. This variance calculation is materially skewed by including 2009 in a three-year historical average calculation because it was not a typical year given that the Company needed to control expenses to respond to the revenue fall-off related to the recession. Removing the 2009 actual [cost number] from average calculation reduces the proposed adjustment by over $6 million. In addition, the proposed adjustment does not consider certain major projects planned for 2012 [that are] not included in historical trends, such as $3 million of maintenance for the Glacier Hills wind project. Given these facts, and the fact that Mr. Gorman is cherry-picking what were the only possible downward adjustments from a PSCW proceeding that ultimately did not impact the PSCW decision in that proceeding, [his] proposed adjustment should not be adopted.

WEPCo's initial brief, pp. 109-100 [citing 3 Tr 99].

The ALJ agrees with the position expressed by the Company, and finds that, based largely on the above-quoted testimony from Mr. Ackerman, the $10.1 million downward adjustment to other production expense proposed by the Mines (and supported by Verso) should be rejected. It is thus recommended that the Commission adopt, for use in setting the utility's rates in this proceeding, the 626,325,575 total electric utility expense figure included in WEPCo's initial filing.

[16] In addition, the Mines contend that its proposed adjustment would also reflect "WEPCo's three-year (2008-2010) historical cost average of non-labor gas turbine maintenance expenses increased for inflation." Mines initial brief, p. 41.

d. Board of Directors Expense

WEPCo's computation of its revenue requirement also includes $1,599,132 (on a total electric utility basis) that it asserts is the Company's recoverable allocated share of the fees and expenses incurred by the Board of Directors for WEC, which--as noted earlier--serves as WEPCo's parent company. The Mines, however, contend that because "WEC and WEPCo have independent boards," WEC's board "does not add any value to the direction and management of WEPCo" beyond what is provided by the utility's own board. Mines' initial brief, p. 30. This fact, when coupled with the PSCW's denial of such cost recovery in Wisconsin (see, i.e., Mines' initial brief, p. 30), leads the Mines--as well as Verso--to advocate the removal of all WEC Board of Directors costs from the computation of WEPCo's revenue deficiency or sufficiency.

The ALJ generally takes a dim view of requests from any utility to include, in the computation of its rates, costs relating to the activities of its parent company's Board of Directors. Nevertheless, in this case, the ALJ finds that inadequate reason has been shown for excluding their recovery. Specifically, as pointed out by Mr. Ackerman:

> The WEC, WEPCo, and [Wisconsin Gas, LLC (WG)] boards are integrated to avoid redundancies and minimize costs to all companies. For instance, the WEC board addresses issues that impact both utilities simultaneously, rather than addressing the issues in the separate utility board meetings. The WEC directors serve on the WEPCo and WG boards and committees, so there is a shared knowledge base, and the board meetings are scheduled at the same time to minimize travel costs. That allows coordination of discussion of issues so that the directors' and officers' time is used efficiently. This avoids redundancies and, because of this coordination of efforts, total board-related costs between WEPCo, WG, and WEC are less than if the holding company did not exist at all.
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> * * * * *
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> Total board-related costs are less because a single annual retainer fee is paid and, where applicable, a single quarterly committee chair retainer fee

> is paid to each director for serving on each board. All directors serve on all three boards.

3 Tr 100. Because the same individuals serve as directors of each of the three entities, it appears that their expenses are paid by WEC, at which point those costs are then allocated among the three companies involved. See, WEPCo's initial brief, p. 111. Such a structure--while somewhat unique in the realm of utility operation--serves to greatly assuage the concerns that generally lead regulatory agencies to deny recovery of costs like those currently at issue. Evidence of the same can be gleaned from the July 1 order, where it was stated that:

> The Commission finds that inclusion of the allocated portion of board of directors expense is appropriate in this case. WEPCo has initiated an efficient and sensible plan to integrate its board of directors by sharing the board between the three entities. This is not a case in which the company seeks to allocate board expenses from a parent company that is in addition to board expense for its own board. Rather, these are shared costs that have been allocated between the three sharing entities. Moreover, it appears to the Commission that there may be inherent cost savings, as well as advantages for making coordinated decisions that will protect the utility and its ratepayers. Neither the costs themselves nor the formula for calculating the allocation were challenged as unreasonable or imprudent in amount. For all of the above reasons, the Commission rejects the Mines' exception on this issue.

July 1 order, pp. 47-48.

Thus, based both on the record assembled in this proceeding and the ruling of the Commission on this matter as quoted above, the ALJ finds that the allocation of the joint board of directors expense is reasonable and recommends that the Commission include those costs in computing WEPCo's revenue deficiency or sufficiency in this case.

3. Depreciation and Amortization Expense

WEPCo requested, for use in setting its rates in this case, a level of depreciation and amortization expense for the 2012 test year of $235,536,334 on a total electric utility basis (which converts to $12,493,767 on a Michigan retail customer basis). See, Exhibit A-3, Schedule C1, line 5. None of the parties to this proceeding took issue with that requested expense level, and the ALJ, thus, finds that it should be adopted.

4. Recoverable Tax Expense

The Company next presented, through various testimony and exhibits offered by Mr. Ackerman, its calculation of (1) taxes-other than income taxes, (2) federal income taxes, and (3) state taxes. The Staff's witness on these issues, Gretchen M. Wagner, an Auditor in the Act 304 Section of the Commission's Regulated Energy Division, offered testimony suggesting changes to the second and third components of the overall tax expense addressed by Mr. Ackerman. 3 Tr 574-576.

WEPCo now "accepts the methodology underlying [the] Staff's adjustments" to its federal income tax cost and state tax expense, while also recognizing that "the amount of taxes may change depending on the Commission's final decision as to revenues, expenses and rates." WEPCo's initial brief, p. 113. None of the other parties take issue with either the methodology or the resulting figures (tentative as they may be) suggested by the Staff.

As a result, the ALJ finds that the Company's proposed tax-related expense, as adjusted by the Staff's suggested methodology, should be adopted for use in this proceeding. It is therefore recommended that the Commission adopt the Staff's proposals regarding the computation of tax-related expense when issuing its final order and establishing WEPCo's rates (as well as when making the ultimate calculation of the revenue conversion factor to be applied in this case).

5. Revenue Multiplier, Jurisdictional Conversion Factor, and AFUDC Accounting

The last three areas to be considered in any calculation of a multi-state utility's computation of NOI concern (1) the appropriate gross revenue multiplier, (2) the jurisdictional conversion factor, and (3) the selection of accounting standards to be applied to such items as AFUDC.[17] Here, it appears that WEPCo and the Staff have agreed on each of these matters. For example, the Staff specifically adopted the Company's proposed gross revenue conversion factor of 1.6680%, assumes that a jurisdictional conversion factor of 6.595% will be applied when setting rates for Michigan customers, and accepted the utility's proposed application of Wisconsin accounting practices with regard to the treatment of such things as AFUDC. See, Staff's initial brief, pp. 24-27. Because no other party has objected to their jointly-proposed treatment, the ALJ recommends that the Commission apply the factors and accounting treatment agreed to by WEPCo and the Staff.

C. Adjusted NOI Summary

As reflected on Attachment A to this PFD, which summarizes the above-described adjustments to WEPCo's initially proposed positions regarding its utility-wide revenues and expenses for the 2012 test year, the ALJ concludes that a more reasonable projection of its total electric utility adjusted net operating income would be

[17] The acronym "AFUDC" stands for Allowance for Funds Used During Construction. In the present case, this would apply to costs borne by the Company during the construction of the PTF facilities, among other things.

$329,734,274. This figure corresponds to $12,917,611 on a Michigan jurisdictional basis. Still, it should be noted that (based on various rate base adjustments and the return on equity recommendation also contained in this PFD), some slight revision to depreciation expense, AFUDC, and other NOI components have been--or may be--required as part of both this PFD and the Commission's final order in this case.

VI.

REVENUE DEFICIENCY

Based on the foregoing findings, WEPCo's approximate adjusted gross revenue deficiency for the 2012 test year (inclusive of the RE adjustment and recognizing the ERGS increment at 100%, as opposed to 108%),[18] can be computed as follows:

Rate Base	$354,886,352
Rate of Return	X 6.25%
Income Required	$22,301,058
Adjusted Net Operating Income	$12,917,611
Income Deficiency	$9,383,447
Revenue Multiplier	X 1.6680%
Revenue Deficiency	$15,651,590
Act 295 RE Adjustment	($4,129, 051)
ERGS Increment at 100% vs 108%	($1,512,017)
Adjusted Gross Revenue Deficiency	$10,010,522

[18] Neither the approximate $4.1 million Act 295 RE adjustment nor the $1.5 million reduction from the parties' initially proposed revenue deficiency based upon the difference between use of the 100% or 108% ERGS increment appear to have led to any significant dispute among the parties. As a result, and for the sake of clarity, they are included in this computation.

VII.

COST OF SERVICE, COST ALLOCATION, AND RATE DESIGN

The Commission must follow the requirements set forth in Section 11 of Act 286, MCL 460.11, in setting rates based upon a cost of service study (COSS), the end result of which is to establish revenue requirements by specific customer class or rate schedule. To facilitate this process, the Commission directed WEPCo, as part of the utility's prior rate case order, to serve upon the parties a copy of its COSS in Excel format. The Staff relied heavily on the Company's COSS in developing its own version. Thus, although it essentially produced its own, full COSS, the Staff's version used the same allocation methodologies as the utility, and simply made adjustments where necessary to reflect the dollar values proposed in the rest of Staff's presentation, as described by Bonnie Janssen, a Public Utilities Engineer Specialist in the Rates and Tariffs Section of the Commission's Regulated Energy Division. See, 3 Tr. 518-520.

In this proceeding, four issues have arisen concerning the allocation of WEPCo's total electric utility revenue requirement. The first concerns the general methodology by which WEPCo allocated its transmission costs among the Federal, Wisconsin, and Michigan jurisdictions. The next three issues concern the specific allocation of transmission costs, distribution costs, and transmission costs among the Company's various rate classes in Michigan. In addition to those four areas of dispute, a handful of rate design and tariff change matters have been raised in this case, the most significant of which involves various concerns expressed by Verso regarding the utility's Schedule A demand charge. Each of these issues will be dealt with separately.

A. Cost Allocation, Jurisdictional and Michigan-Based

1. Jurisdictional Allocation of Transmission Expense

WEPCo's witness regarding cost allocation and rate design, Eric A. Rogers, testified that in preparing its COSS, the utility allocated its total transmission expense among the three jurisdictions using the 12 coincident peak (CP) 75% demand/25% energy formula set by the Commission in its May 10, 1976 order in Case No. U-4771[19] See, 3 Tr. 124. That is, 75% of the Company's transmission cost--which essentially consists of charges paid to the American Transmission Company (ATC)--is allocated based on an average of the 12 monthly CP demand values, and the remaining 25% is based on energy usage. The Staff used the same jurisdictional allocation formula in its COSS. See, Staff's initial brief, p. 32.

In contrast, the Mines argue that transmission expense should be allocated among the various jurisdictions on a 12CP, 100% demand basis. See, Mines' initial brief, p. 41. In support of that argument, they note that ATC charges WEPCo for transmission service based on a 12CP, 100% demand basis. Thus, the Mines claim that, to be "consistent with cost causation principles," their 12CP demand allocator" is more appropriate for use in this instance. Id. Moreover, they contend that "because Michigan's load factor is much higher than that of WEPCo's Wisconsin and Federal Energy Regulatory Commission (FERC) jurisdictions," use of the 12CP 75/25 allocation

[19] Section 11(1) of Act 286 requires that, for all Michigan utilities with over 1 million customers, the cost of serving each customer class shall be based on the allocation of production-related and transmission expenses using a 50-25-25 method of cost allocation. However, as noted by various parties in this proceeding, and previously recognized by Commission order, that requirement is not applicable to WEPCo on the grounds that it has less than 30,000 customers in Michigan. See, i.e., Staff's initial brief, p. 29; July 1 order, p. 50.

factor "inappropriately increases the transmission expense allocated to Michigan," making its proposed application in this case "unjust and unreasonable." Id.

The ALJ does not find the Mines' contentions (in favor of rejecting the long-standing allocation methodology and supplanting it with a significantly different method) adequately persuasive. This decision is based on the following two factors. First, although being given numerous opportunities over nearly a 36-year period, the Commission has elected to retain the 12CP 75/25 allocation factor for use in assigning transmission costs. For example, when recently establishing revised standardized rate case filing requirements, the Commission elected to retain the 12CP 75/25 method. See, the Commission's December 23, 2008 order in Case No. U-15895. Moreover, in WEPCo's most recent general rate case (Case No. U-15981), the Commission rejected arguments by the Mines that were essentially a duplicate of those offered here. See, July 1 order, pp. 51-52. Second, and noted both in briefs and in the July 1 order, the Commission's decision in Case No. U-4771 was based on an engineering study that looked at the actual design of electric transmission systems and, in doing so, concluded that such design must--by necessity--address both the demand and energy aspects of the system. See, Id., p. 52.

As a result, the ALJ recommends that the Commission adopt the joint proposal by WEPCo and the Staff to employ the 12CP 75/25 formula for allocating the Company's total transmission costs among the FERC, Wisconsin, and Michigan.

2. Distribution-Related Cost Allocation

WEPCo's witness regarding cost allocation, Mr. Rogers, provided testimony explaining the various methodologies used to allocate discrete components of the

Company's distribution costs, including substation-related O&M expense, depreciation, and property tax. See, 3 Tr. 124-127. Apparently based on recent improvements to its distribution system, the investment in the Company's substation-related total utility plant in Michigan has grown from $7.7 million at the time of its last rate case to $15.2 million at present. See, July 1 order, p. 53, and 3 Tr 272.

The Mines and Verso object to the amount of these costs and others, that are--through the joint utility/Staff allocation structure--assigned for recovery from them. According to the Mines' witness on this matter, James W. Collins, Jr., reliance by WEPCo and the Staff on a non-coincident peak (NCP) demand allocation methodology for these expenses results in an "over-allocation of costs" that is both "unjust and unreasonable, and does not reflect WEPCo's actual costs to provide distribution service to the mines." 3 Tr 273. Because they are "served from just two dedicated substations that are physically and electrically separated from each other, and from the rest of the WEPCo's distribution system," the Mines contend that the "distribution costs of serving the Mines can and should be isolated and separately assigned rather than allocated." Mines' initial brief, p. 53 [citing 3 Tr 273-274]. The same is true of Verso, who notes that "the distribution facilities [it uses] were constructed specifically for the Quinnesec Plant." Verso's initial brief, p. 4. As a result, these intervenors assert, among other things, that:

> [D]istribution plant investments and expenses related to the operation of the dedicated substations that serve the Mines should be assigned to them in WEPCo's [COSS] based on the ratio of WEPCo's costs of all distribution substations serving the Mines [on the one hand] to WEPCo's total net plant costs of all distribution substations in WEPCo's Michigan service area [on the other].

Id., p. 56.

Based both on the evidence provided in this proceeding and the application of utility cost allocation as a whole, the ALJ finds the NCP demand allocation methodology advocated by WEPCo and the Staff to be preferable to that suggested by the Mines and Verso. It bears noting that, pursuant to the COSS studies performed by the Company and the Staff, the only distribution system-related costs assigned to the Mines and Verso appear to be those relating to substation and metering expense. As specifically pointed out by Mr. Rogers, "all other components of the distribution system are allocated [to them] at zero cost." 3 Tr 146. Moreover, he noted that with regard to the allocation of substation O&M expense and depreciation costs:

> It is correct to use the ratio of allocated substation plant costs to allocate substation O&M costs, and depreciation expense (this is essentially what our model does), but it is not appropriate to use the $3,890,895 value obtained through the data request [from the Mines] as the basis for the allocation of costs – either plant costs or O&M costs. As indicated in my direct testimony on page 17, line 28, we are required by the [Commission] to allocate distribution costs among customer classes on the basis of demand. Allocation of distribution costs among customer classes based upon demand is more appropriate than allocation based upon total plant assigned to each rate class because it eliminates disparate treatment of specific customers or customer groups based upon the specific substation plant serving them. It would not be reasonable to penalize a customer simply because the Company built a new or replacement substation to serve the specific customer. [The Mines' witness], however, is asking for favorable treatment simply because the substations serving the Mines may be older and more fully depreciated than the average substations in [the utility's] Michigan service territory.

Id., p. 147. This certainly raises the likelihood (as previously noted by the Commission) that, if the utility chose to replace the substations currently serving the Mines and Verso, these intervenors "would likely be before the Commission seeking to argue the opposite of what they argue here – that is, that direct assignment of the costs associated with these substations is unfair." July 1 order, pp. 53-54. As noted earlier in the PFD, the

ALJ gives a lessened degree of credence to assertions that appear based more on opportunism than consistent regulatory application.

As a result, the ALJ recommends that the Commission reject the joint proposal of the Mines and Verso regarding the allocation methodology to adopt with regard to WEPCo's distribution-related expenses and, instead, adopt the methodology relied upon by both the utility and the Staff in preparing their respective COSS proposals.

3. Transmission-Related Cost Allocation

As with its jurisdictional allocation of transmission-related expenses (discussed above), WEPCo assigned the Michigan-based portion of its transmission-related expenses based on the same 12CP 75/25 formula. The Staff's COSS did the same, allocating 75% of the total cost on the basis of demand, with the remaining 25% of the Company's Michigan jurisdictional transmission costs distributed to rate classes based on energy usage. See, e.g., WEPCo's initial brief, p. 118.

With regard to the intra-Michigan allocation of these expenses, the Mines again advocate use of the 12CP, 100% demand methodology. Their position on this topic is based on essentially the same arguments offered in support of making the jurisdictional allocation of the company-wide transmission on this basis. See, e.g., 3 Tr 279-282.

Based both on the findings regarding transmission cost allocation expressed above (albeit concerning jurisdictional allocation, as opposed to Michigan cost allocation only), as well as the fact that the Commission specifically rejected the Mines' arguments on intra-state transmission cost allocation in both its July 1 and October 14, 2012 orders in Case No. U-15981, the ALJ concludes that the 12CP 75/25 methodology should be adopted. It is thus recommended that the Commission apply the allocation structure proposed by both WEPCo and the Staff, as opposed to that advocated by the Mines.

4. Production Cost Allocation

Consistent with the language included in Paragraph 11.h of the settlement that the Commission approved by way of its November 13, 2008 order in Case No. U-15500, both WEPCo and the Staff included, as part of their respective COSS submitted in this proceeding, a production cost allocation based on the 12CP 75/25 methodology. See, WEPCo's initial brief, p. 119; Staff's initial brief, p. 33. This methodology was, those two parties note, subsequently approved (over the Mines' objection) in the Commission's most recent rate case for WEPCo. See, July 1 order, pp. 54-55,

Once again, the Mines contest the allocation methodology proposed by both the utility and the Staff. In this instance, however, the Mines proposal shifts from favoring a 12CP 100% demand methodology to a summer-oriented 4CP 75/25 structure. As a result, the only difference between the WEPCo/Staff position and that offered by the Mines is that the Mines want to tie the peak day component to four summer months (June through September, based on Mr. Collins' analysis of the utility's load data), when the Company tends to experience its peak sendout. See, Mines' initial brief, pp. 60-61. According to the Mines, because demand-related production costs are incurred to meet the utility's greatest electric usage, an allocation based on the 4CP demand "will more accurately assign demand-related production costs to ratepayers based on their contribution to WEPCo's system peak demands." Id., pp. 61-62.

The ALJ does not find the Mines' analysis persuasive. The reasoning offered by Mr. Collins and adopted by the Mines has previously been rejected by the Commission on the grounds that more of the electric demand that a utility responds to is actually constant (e.g., base load) demand, as opposed to peak demand. As explained in a fairly recent rate case order involving Consumers Energy Company (Consumers):

> The Commission adopts the findings and recommendations of the ALJ and approves the Staff's proposed [allocation] method. This method, in comparison to the old method advocated by ABATE, shifts 50% of generation plant costs away from system peak demands, and reclassifies them as related to on-peak energy or average demand. This recognizes that more of the demand to which Consumers is responding is constant demand rather than peak demand. In previously authorizing the use of this method, the Commission stated that, "While the total amount of generation capacity needed by Consumers is based on peak demand, the greatest amount of investment is incurred to serve base load and intermediate load. . . . [I]t is appropriate to increase the weight given to average demand in the allocation of the production plant costs relative to peak demand.

June 10, 2008 order in Case No. U-15245, p. 66.

Consistent with the conclusion expressed in that case, the 12CP 75/25 method currently advocated by WEPCo and the Staff gives more weight to constant demand, as well as base and intermediate load, than does the 4CP 75/25 methodology proposed by the Mines. This was reinforced by the Commission in its July 1 order, where it rejected the Mines' proposal to change to a 4CP component for the allocation of production costs, stating:

> In their exceptions, the Mines contend that they argued in favor of a 4CP 75/25 production cost allocation, but that their arguments were ignored by the ALJ. The Mines argue that demand-related production costs are usually incurred in proportion to the maximum capacity of a utility's production facilities. The Mines argue that the demand component of production costs should be distributed using factors that reflect the utility's system peak demand. The Mines maintain that WEPCo's load data shows that WEPCo's four highest monthly system peak demands, from 2003 to 2007, occurred in June to September. On that basis, the Mines argue that using 4CP rather than 12CP for 75% of fixed production costs will more accurately assign these costs to ratepayers based on their contribution to peak demands.

> In reply, the Staff supports continued use of the production allocation method set in the May 10, 1976 order in Case No. U-4771, . . . which has long been applied to utilities serving fewer than one million customers. The Staff points out that the Commission chose not to revise this method in 2008 when setting new filing requirements. The Staff argues that the Mines have no evidence showing that changed circumstances require a new method.
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> The Commission is persuaded that it should retain the production cost allocation method that has been in place for smaller utilities for many years. The Mines have failed to show that any conditions have changed sufficient to warrant this move away from constant demand to peak demand.

July 1 order, pp. 54-55.

Based on the orders quoted above, the ALJ finds that the Commission should reject the Mines' proposed shift to a 4CP 75/25 production cost allocation methodology and, instead, adopt the joint WEPCo/Staff proposal to continue its use of the 12CP 75/25 method.

B. Rate Design and Tariff Changes

1. Schedule A Demand Charge and Related Issues

Verso offered testimony by its Manager of Manufacturing Excellence, Steven Brooks, requesting that the Commission "modify Schedule A to reduce or eliminate the Minimum Demand Charge in light of the expansion of Verso's [own] generating facilities at its manufacturing plant" in Quinnesec.[20] 3 Tr. 465. By way of rebuttal testimony filed on December 28, 2011 on behalf of WEPCo's rate design witness, Mr. Rogers, it was

[20] As noted in its initial brief, "Verso and its affiliates operate a renewable energy facility at the Quinnesec Plant that provides a portion of its energy needs." Verso's initial brief, p. 5. Moreover, this intervenor pointed out that it expanded that facility by installing a new 28 to 31 MW generator, which became operational in December 2011. Id., citing 3 Tr 466.

explained that although Verso qualifies to take service under several rate schedules, all of them except for Schedule A contain a 300 kilowatt (kW) minimum demand charge. See, 3 Tr 148. Thus, based on Verso's installation of a new steam turbine generator, Mr. Rogers stated that:

> [WEPCo] would agree to incorporate the 300 kW minimum demand charge into Schedule A consistent with the other General Primary tariffs. Based on the projected billed demand provided by Verso, the 300 kW minimum demand should not constitute an unfair and harmful cost to Verso.

Id., at 148-149. By way of its initial brief (which was filed on March 1, 2012), Verso stated that "the proposed revision to the terms of the Minimum Demand Charge is acceptable to Verso, and the Commission should approve this revision to Schedule A." Verso's initial brief, p. 7.

However, in a somewhat novel approach, Verso asserts that the agreed-upon revision to Schedule A should be deemed to have been "effective as of the date WEPCo agreed to make this change, December 28, 2011." Id. According to Verso, giving immediate effect to this proposed tariff change is justified by the fact that "this is one instance, unlike the many instances in which unilateral changes were made to Schedule A without agreement by Verso or prior owners of the Quinnesec Plant," in which both parties have agreed on a proposed revision. Id., citations omitted.

Although agreeing to make the change in the Schedule A minimum demand charge, WEPCo objects to doing so on the retroactive basis proposed by Verso. The Company contends that, not only did it "not agree in its rebuttal testimony to implement, effective as of December 2011 and without required Commission approval, a change in the Schedule A minimum demand requirement," doing so would have violated its duty to charge Commission-approved rates. WEPCo's reply brief, p. 39. The Staff agrees with the utility, and asserts that because Commission orders are--by necessity--prospective in nature, the parties' agreed-upon change to Schedule A should only take effect concurrently with all other rate revisions approved by the Commission's final order in this proceeding. See, Staff's reply brief, p. 19.

Based both on the agreement of the parties and the uncontroverted testimony offered in this proceeding regarding the recent addition to Verso's self-generating capacity, the ALJ finds that (for consistency's sake, if nothing else) the addition of a 300 kW minimum demand charge to Rate Schedule A makes good sense. Nevertheless, he agrees with WEPCo and the Staff regarding the start date for any such change. As those two parties correctly note, the Company is bound by law to charge only the rates approved by the Commission. This is true regardless of whether those rates are specifically detailed in the tariff sheets made available for use by all comers, or arise from special contracts whose approval by the Commission is still required.

As a result, the ALJ recommends that the Commission (1) approve the proposal to modify Schedule A to include a 300 kW minimum demand charge, and (2) make the effective date of that revision correspond to the effective date of all other rates and tariff provisions approved by way of its final order in this case.

2. Verso's Refund Request

Based largely on the provisions of its special contract with WEPCo, as well as the fact that the utility self-implemented a portion of its initially-requested rate increase subsequent to the December 28, 2011 filing of rebuttal testimony expressing its agreement to modify Schedule A, Verso requests a full refund of "any additional

Demand Charge to Verso since January 5, 2012[21] over that which would have been calculated based on 300 kW of minimum demand." Verso's initial brief, p. 11. According to this intervenor, the fact that WEPCo's "interim rate increase is by law subject to refund depending on the final rates approved by the Commission," coupled with the fact that the order approving that particular interim rate increase "authorized a rate design different than [otherwise] mandated by [Act 286]," supports its requested refund of any additional charges assessed in the interim. Verso's initial brief, p. 11.

WEPCo objects to Verso's requested refund on three grounds. First, it points out that the provision of Act 286 dealing with the potential refunding of any interim rate increase--namely, that set forth in Section 460.6a(1)--allows for refunds "only to the extent that the total revenues collected exceed the total revenues that would have been produced by the rates subsequently ordered by the Commission." WEPCo's reply brief, p. 39. Second, it notes that nothing in the Commission's December 20, 2011 order regarding the Company's requested self-implementation mentioned altering the demand charge for Schedule A. See, Id. Third, the utility asserts that (notwithstanding claims to the contrary by Verso) the rebuttal testimony submitted in this proceeding in no way included an agreement to make the change to Schedule A "effective as of December 2011 and without required Commission approval." Id.

The ALJ agrees with WEPCo in this regard, and finds that the Commission should reject Verso's request for a refund of any alleged excess demand charges paid pursuant to the Commission-approved language contained in Schedule A subsequent to December 28, 2011. A reasonable reading of the record makes clear that WEPCo's

[21] As noted previously, WEPCo self-implemented, pursuant to the Commission's December 20, 2011 order in this case, a portion of its initially-requested rate increase effective January 5, 2012.

rebuttal testimony on this matter, in which it suggested revising Schedule A to include a 300 kW minimum demand provision, was referring to the rates and charges to be imposed following the Commission's final order in this proceeding. Moreover, even if the Company wished to begin providing service under a modified version of Schedule A, it would have needed explicit Commission authorization to do so. As things stand, until the Commission rules on whether or not the proposed revision of Schedule A should be approved, the currently-existing provisions of that schedule (under which Verso was presumably billed) should be followed.

3. Verso's Request for Declaratory Rulings

In addition to its request for a potential refund of any excess demand charges paid from January 5, 2012 forward, which had as its foundation language contained in its special contract with WEPCo, Verso requests that the Commission provide a pair of declaratory rulings concerning its interpretation of provisions contained in Paragraph 9 of that contract (approved by the Commission by way of its November 9, 1989 order in Case No. U-9429). First, Verso requests a ruling stating that its right to elect to be billed under the firm demand and energy charges contained in any of the applicable General Primary Service Rate categories is triggered by a change in the firm demand charge or energy charge it has historically paid, including any interim or self-implemented rate revision. See, Verso's initial brief, pp. 8-10. Second, Verso seeks a declaratory ruling stating that, should it select another rate under which to be billed, Paragraph 9 would require not only the application of that rate's firm demand and energy charges, but also the use of that rate's minimum demand provisions. Id., p . 10.

Based in large part on the Commission's general aversion to issuing declaratory rulings, the ALJ is remiss to weigh in on either of the two proposals described above, particularly in the midst of a proceeding initiated pursuant to Act 286. With the extremely strict time constraints established by the Legislature for issuing a final rate case order (and with the penalty for failing to do so being that the utility can implement whatever rate increase it initially proposed), the ALJ finds that matters like those raised by Verso should be addressed, if necessary, in the context of individual complaint cases. As a result, the ALJ recommends that the Commission elect to defer ruling on either of these two matters unless and until they are raised in a separate docket.

4. Other Tariff Proposals

In addition to the previously-addressed revision to Schedule A, three other tariff-related issues are worth mentioning.[22] The first two concern LED lighting, while the third relates to the Company's Edgewater-5 sales credit.

By way of the Commission's April 27, 2010 order in Case No. U-16217 (the April 27 order), WEPCo was directed to propose new tariff language dealing with customer-owned LED per-lamp (e.g., unmetered) lighting rates. However, as Mr. Rogers noted, the Company has no per-lamp lighting rates that apply to customer-owned lighting of any type, and its Michigan customers who own their own lights (whether Incandescent, Mercury, LED, etc.) generally take service under per-kWh rates. See, 3 Tr 140. Thus,

[22] Although WEPCo and the Staff offered a host of proposed changes to the Company's rates, tariffs, rules, and regulations applicable to Michigan customers, the vast majority of those proposals were unopposed. Due to their lack of opposition, the ALJ recommends that--unless they relate to areas addressed elsewhere in this order and in which either the corresponding position offered by WEPCo or the Staff was rejected--the Commission should approve those changes. More importantly, it bears noting that (as specifically expressed by witnesses for both the Company and the Staff) the new rates proposed in this case should serve to fully eliminate the previously-existing residential rate subsidy, consistent with both the limitations and requirements set forth in Section 11(1) of Act 286. See, 3 Tr 132-133; 3 Tr 535.

because no customer's ability to switch to LED lighting will be hindered by the absence of tariffs for unmetered service to such lights, the utility finds no need to propose tariffs like those envisioned in the April 27 order. See, Id. The only other party to weigh in on this issue was the Staff, whose witness on this matter, Mr. Revere, agreed with WEPCo's position. See, 3 Tr. 536. Based on the current structure of the Company's rates (specifically with regard to municipal street lighting), the ALJ finds that the joint position of the Company and the Staff makes good sense, and thus should be adopted by the Commission.

The second matter concerns the experimental pilot rate designated as LED1. According to Mr. Rogers, the company proposes to extend that rate for two additional years, through June 30, 2014. See, 3 Tr 140. Again, based on the testimony offered by Mr. Revere, the Staff supports the utility's position, and no party has challenged WEPCo's request. As with the preceding issue, the ALJ finds that the utility's proposal should be adopted, and thus recommends that the Commission authorize the extension of Rate LED1 as requested by the Company.

Third and finally, WEPCo proposes (based again on testimony from Mr. Rogers) the elimination of the existing Edgewater-5 sales credit concurrent with the effective date of the rates established by the Commission's final order in the present case. See, 3 Tr 140. According to testimony offered by Mr. Revere, the Staff agrees that the sales credit should be removed from rates consistent with the Commission's December 2, 2010 and April 26, 2011 orders in Case No. U-16366. See, 3 Tr 535. In so doing, the Staff notes that "the credit was implemented to give customers the benefit of the plant's removal from rate base" until new rates were set in this case that reflect that facility's removal. Yet again, none of the other parties to this proceeding object to that proposal.

Although the fact that the record in Case No. U-16366 was reopened pursuant to the Commission's April 26, 2011 order has led to a situation where the final imputed purchase price (to be used for ratemaking purposes) has not yet been specifically established, there appears no reason to refrain from removing the current Edgewater-5 sales credit from the Company's rates. If necessary--based on the ultimate outcome of the Commission's order in the reopened proceeding--a new, temporary surcharge or credit could (and likely will) be established by the Commission. As a result, the ALJ finds that the uncontroverted testimony offered by both Messrs. Rogers and Revere supports making this change in the utility's tariffs, and thus recommends that the Commission approve the requested elimination of the existing Edgewater-5 sales credit.

VIII.

RATE CREDITS AND MISCELLANEOUS ISSUES

A. Curtailable Demand Credit

Curtailable demand credits (often referred to as "interruptible" or "non-firm" credits), are billing credits extended to customers that take electricity on a curtailable basis. The theory behind such credits is that, because curtailable loads contribute less to the utility's peak demand requirements and costs, thus helping forestall the need to build or purchase additional generating capacity, customers willing to have their power usage interrupted during times of peak energy demand should be rewarded in some fashion. In WEPCo's Michigan service territory, the level of the Company's curtailable demand credit is "based upon the marginal cost of production capacity in the form of a combustion turbine (CT) unit." WEPCo's initial brief, p. 122 (citing 3 Tr 143). Since their initial adoption, the Company states, it has "consistently proposed to maintain the credits at such level even though the estimated cost of building a CT unit has increased or decreased from time-to-time in the interim." Id.

However, in the course of its most recent rate case (e.g., Case No. U-15981), the utility proposed maintaining the credit's existing level, despite noting that an increase in the estimated cost of building a new CT unit had occurred. According to WEPCo, its decision to do so was "based on rate stability and an expectation that the cost to construct a CT unit would go down in the next rate case." Id. Although the Staff agreed with the Company that the existing credit level should simply be maintained in that case, the Mines and LPC argued that the credit should be increased concurrent with the proposed rise in the utility's demand charge. See, Id., at 123. The Commission disagreed with those two intevenors, stating instead that:

> The Commission finds that WEPCo should continue to apply the current curtailable demand credit. The rise in WEPCo's demand charge is driven by the rise in transmission costs, but the credit does not include transmission costs. The Commission finds that the credit should remain unchanged.

July 1 order, p. 58.

Against that background, Mr. Rogers indicated in the current proceeding that data assembled by the Company indicates that the marginal cost of generating capacity in the form of a CT unit was slightly lower than that computed in Case No. U-15981, and that the marginal cost is actually higher than the current market value of capacity. See, WEPCo's initial brief, p. 123 [citing 3 Tr 138-139, 144]. Nevertheless, the utility continues, it elected not to reduce the curtailable demand credit, but rather proposes to "maintain the current level of non-firm credits." Id.

The Staff agrees, in large part, with WEPCo's analysis, and supports leaving the curtailable demand credit at its current level. See, Staff's initial brief, pp. 34-37. Still, it recommends that any future calculation of the credit be modified to (1) incorporate the line losses from the generation level, as opposed to the transmission level, and (2) use a billed demand factor specifically tailored to Rate CpCL customers (e.g., the Mines). See, Id., p.36. Notwithstanding either its above-described recommendation or the fact that WEPCo has now expressed agreement with implementing those two changes on a going-forward basis (See, WEPCo's reply brief, p. 42), the Staff goes on to point out that:

> [T]he appropriateness of adjusting the credit based on this methodology should still be examined in light of the state of the appropriate capacity markets. The Staff agrees with the Company that the avoided cost methodology is not reflective of the present cost-savings actually provided by non-firm load, given the current market for capacity. Therefore, Staff recommends that the interruptible credit remain at its current level.

Staff's initial brief, pp. 36-37.

In contrast, the Mines express concern about the Company's calculation of this credit. According to their witness, although the credit adopted in this case "should include a capacity reserve margin adjustment and a line loss factor which translates the avoided cost at [the] generation level to an equivalent credit at the customer meter," WEPCo's proposal did not. Mine's initial brief, pp. 10-11. Specifically, Mr. Gorman asserted that a more reasonable curtailable demand credit could be achieved by, among other things, (1) excluding the capacity contribution index factor proposed by the Company, which he calculated to be 4.17%, (2) including a 14.5% capacity reserve margin adjustment, and (3) also including a line loss factor of 4.0%. See, Id., p. 11. If all of the steps recommended by their witness were taken, the Mines continue, the overall effect would be to increase the curtailable demand credit, and thus decrease by $2,217,000 WEPCo's Michigan jurisdiction's revenue requirement (and with it, albeit to a lesser degree, the amount the Mines would pay for their electric service). See, Id.

Based on a reading of the record as a whole, the ALJ finds that the curtailable demand credit sought by the Mines should be rejected, and that the credit proposed by WEPCo and supported by the Staff should be adopted instead. As noted in rebuttal testimony offered by the Company's expert, Mr. Rogers, the existing credit is likely too high already given the current state of the capacity markets. See, 3 Tr 144. Moreover, with regard to the Mines' suggestion to include a capacity reserve margin adjustment, WEPCo's witness pointed out that:

> There are two reasons why our credits for non-firm load should not reflect our reserve margin. First of all, our non-firm contracts have a maximum term on only three years (shorter than the time required to build new capacity, even combustion turbines), so long-term availability is not assured. Secondly, our non-firm tariffs specify a response time of two hours. In order to have contingency reserve value in the MISO market, response times must be ten minutes or less.

3 Tr 145. For these and other reasons, the ALJ recommends that the Commission adopt for use in setting rates for the 2012 projected plan year, the curtailable demand credit advocated for use by both the Company and the Staff.

B. DOE Settlement Credit

In its application, WEPCo proposed to credit its Michigan customers their allocated share of the overall proceeds, less litigation costs, received as a result of its litigation with the DOE with regard to spent nuclear fuel. Specifically, the Company sought authority to implement a 12-month revenue credit through the use of a separate line item bill credit, starting on the same date as its self-implemented rate increase in this proceeding. See, 3 Tr 134. According to testimony provided by Mr. Rogers, the utility calculated the Michigan jurisdictional portion of this settlement to be $2,694,144, which resulted in a bill credit of $0.00106 per kWh. Mr. Rogers explained WEPCo's proposed crediting mechanism as follows:

> The credit would appear as a separate line item on the customers' bills. We request escrow accounting treatment of this credit, so that any over or under credit at the end of the twelve-month period would be accounted for. The over or under credit could be considered in a subsequent PSCR reconciliation, as was the final accounting of the Point Beach sales credit, as authorized in Case [No.] U-15220. We understand that implementation of the credit and the escrow accounting would require explicit Commission approval.

3 Tr 134. The Commission approved the initiation of the DOE settlement credit as part of its order regarding self-implementation. See, the Commission's December 20, 2011 order in Case No. U-16830, p. 6.

The Staff's witness on this issue, Ms. Sandhu, recommends that the negative surcharge established by the above-cited order remain in effect for the foreseeable future, stating that:

> Staff recommends that the negative surcharge remain in effect until the amount to be returned to [Michigan] customers is fully refunded through one or more complete billing cycles. WEPCo should accrue and apply interest during the entire duration of the negative surcharge at 0.99%. Within 15 days of termination of the negative surcharge, WEPCo should file a letter in Case No. U-16830 stating that the negative surcharge was terminated and provide a final reconciliation of the negative surcharge. Any residual amount determined to be over-refunded to customers should be captured and reflected through WEPCo's next [PSCR] case as a separate line item.

3 Tr 569.

The Company "accepts the Staff's proposed additions to the crediting procedures and reporting requirements" regarding the previously-approved DOE settlement credit, and none of the other parties to this case object to their implementation. See, WEPCo's initial brief, p. 126. As a result, the ALJ finds the Staff's proposal to be reasonable, and thus recommends that the Commission extend its authorization of the DOE settlement credit, albeit with the changes and additions recommend by the Staff.

C. Bechtel Liquidated Damages

The Bechtel liquidated damages are payments that Bechtel made to WE Power for failing to meet guaranteed in-service dates for the ERGS plants. WE Power then passed along these liquidated damages to WEPCo in the form of bill credits. According to the Company, the total damages paid to WE Power were $5,862,969. Applying a Michigan jurisdictional allocation factor of 6.595% would, it appears, necessitate having $386,700 credited to WEPCo's Michigan customers. See, Exhibit S-7, Schedule H-1. None of the parties currently dispute either the amount or the appropriateness of returning to Michigan ratepayers that portion of the total liquidated damages paid from Bechtel to WE Power. The only issue to be resolved at this time is how to best return this money to WEPCo's Michigan-based customers.

Based on testimony provided by their witnesses (Mr. Gorman and Mr. Birkam, respectively), the Mines and the Staff (at least initially) recommended amortizing Michigan's share of these damages over one year, and using them as an offset to any revenue deficiency arising from this case.[23] See, 3 Tr 370-372, 511. Verso supports that suggested treatment. See, Verso's reply brief, p. 11. In the course of its rebuttal

[23] As noted by the Staff's witness, using a one-year amortization period would reduce the total figure slightly, from $386,700 to $368,912. See, 3 Tr 511.

testimony, WEPCo offered two alternative proposals for the distribution of these funds. The first was to add the amount of the Bechtel liquidated damages to the DOE settlement credit discussed above, thus allowing the total of those two funds to be credited to customers via one line item bill credit, subject to reconciliation. See, 3 Tr 95. The second would be to apply the Bechtel-related proceeds to the asserted revenue deficiency, and to amortize them over either two or three years. Id. Although the Staff disagreed with the utility's first alternative (on the grounds that it could "complicate the DOE credit with an unrelated item"), it suggested that--if the Commission was amenable to implementing a line item credit--"the entire $368,700 [could] be recovered as a line item in the Company's next PSCR reconciliation case." Staff's initial brief, pp. 27-28. WEPCo ultimately accepted the Staff's "alternative proposal to add the entire $386,700 as a separate line credit to PSCR costs." WEPCo's reply brief, p. 43.

The ALJ finds that the Staff's second alternative proposal (to return the Michigan jurisdictional portion of the Bechtel liquidated damages to customers by way of a separate line-item credit to be reconciled through the Company's PSCR process) makes the most sense for three reasons. First, using a reconcilable device like this will, as the utility correctly notes, better avoid the "risk of over-crediting or under-crediting the amount at issue." WEPCo's reply brief, p. 42. Second, such a mechanism will likely provide customers with the benefit of these liquidated damages faster than a reduction in the Company's overall revenue deficiency by the same amount. See, Id., p. 43. Third, keeping the Bechtel liquidated damages credit separate from the DOE settlement credit should make it easier to accurately reconcile each of the two. The ALJ thus recommends that the Commission adopt the second alternative proposed by the Staff.

D. Edgewater-5 Proceeds

The final issue (or, more accurately, set of issues) involves WEPCo's recent sale of the 25% ownership interest it previously held in Edgewater-5 to Wisconsin Power and Light Company (WP&L). During the run-up to that sale, the Commission issued an order in Case No. U-16366 approving the Asset Sales Agreement (pursuant to MCL 460.6q) between WEPCo and WP&L on the condition that the utility (1) implement a $457,912 annual rate credit for its Michigan customers as a result of the transaction, and (2) agree to an imputed price of $60 million, which exceeded the figure contained in the agreement between those two utilities by $21 million. See, the December 2, 2010 order in Case No. U-16366, p. 15. The $457,912 annual credit arising from the sale was designed to reflect all reductions in both plant-related and general expenses, and was designated to continue until the conclusion of the Company's next rate case. See, Id., p. 2. With regard to the imputed purchase price of $60 million, that larger figure was based on the Commission's conclusion that WEPCo failed to produce "any evidence that demonstrates the reasonableness of the price to which it agreed," and because there was "no evidence of a third-party valuation of the property sought to be sold, or an analysis of like plants sold within a recent historical period." Id., p. 13. The Commission thus directed that the $21 million difference between the $39 million purchase price and the $60 million imputed price likewise be addressed in this proceeding. Id., p. 14.

As was briefly mentioned above, the Commission subsequently granted WEPCo's petition for rehearing in Case No. U-16366, and remanded the proceeding to the ALJ "to take additional evidence on the issue of what the imputed value of the asset should be for ratemaking purposes only." Commission's April 26, 2011 order in Case No. U-16366, p. 9. However, due in great part to the fact that the reply briefs filed in the reopened portion of Case No. U-16366 were not received until after the close of the record in this rate case, as well as the fact that the Commission has not yet had an opportunity to re-establish an imputed price for the Edgewater-5 sale, the specific imputed price ultimately arrived at by the Commission for that sale remains an open issue which may need to be dealt with subsequent to the issuance of the final order in this proceeding.

Nevertheless, the parties provided a comprehensive set of proposals designed to address precisely how any difference between the price actually paid for Edgwater-5 and the imputed purchase price--at least once it is established--should be addressed. Along these lines, WEPCo's witness, Mr. Ackerman, testified as follows:

> Regarding self-implementation rates, [WEPCo] concludes that there should not be any offset or credit as the reopened proceedings in Case No. U-16366 will not be complete as of that time. Regarding the final rate relief requested above, [the Company] is of the position that there is not, and will not be, any basis in fact, law, or the evidence for any imputed purchase price above the amount agreed to by the parties in an arms' length transaction for the sale of [the utility's] interest in Edgewater-5. In the event that the Commission were to determine otherwise, any additional imputed proceeds should be: (i) offset first by all transaction costs (estimated at $800,500); (ii) allocated among jurisdictions on the same basis as production plant costs; (iii) [have] the Michigan retail tariff portion first credited against [WEPCo's] unrecovered lease payments for [ERGS-2] between the date of its commercial operation and the date it is first recognized in Michigan rates; and (iv) [have] the remainder, if any, divided between shareholders and Michigan retail tariff customers on a reasonable basis not to exceed fifty percent (50%) for customers.

3 Tr 56. In the context of his rebuttal testimony, Mr. Ackerman went on to suggest that it would also be appropriate to net the associated income tax at 40% on any imputed premium against the imputed proceeds." 3 Tr 93.

Each of the three parties that addressed this matter reached agreement on the second proposal contained in Mr. Ackerman's above-quoted testimony. Specifically, the Staff and the Mines concur with WEPCo that any imputed proceeds from the asset sale should be allocated among its Wisconsin and Michigan jurisdictions on the basis of production plant costs (specifically, through application of the 6.595% allocation factor). See, Staff's initial brief, p. 49; Mines' initial brief, p. 33. In light of the agreement of the parties, the ALJ finds that this particular component of the Company's presentation regarding the Edgewater-5 sale proceeds should be adopted by the Commission. However, a review of the rest of the respective presentations provided by the Mines and the Staff indicates that several points of dispute continue to exist with regard to WEPCo's proposed treatment of the Edgewater-5 proceeds.

Based on the Mines' assessment of testimony offered in the course of the reopened proceedings in Case No. U-16366, they contend that the imputed purchase price initially established by the Commission (which produced incremental purchase revenue of $21 million) "is more than reasonable and should be included in rates as part of this rate proceeding." Mines' initial brief, p. 32. They further assert that:

> If a final order is not issued in Case No. U-16366 before a final order is issued in this case, then any incremental imputed purchase price revenue above the $21 million level should be returned to Michigan retail ratepayers immediately in the form of a rate credit.

Id., p. 33. The Mines go on to contend that no reasonable basis exists for approving WEPCo's request to offset any transaction costs and unrecovered ERGS-2 lease payments from whatever imputed purchase price the Commission ultimately establishes for Edgewater-5. See, Id., pp. 33-34. Moreover, they assert that the "entire amount of the Michigan allocated share of the imputed purchase price should be included in the development of rates in this proceeding" (as opposed to the 50% cap sought by the utility), and that the "imputed purchase price revenue should be allocated among [WEPCo's] Michigan-jurisdictional end-use customers through rates on an energy basis," and offset from the revenue deficiency computed in this proceeding (as opposed to being returned to customers as a credit or negative surcharge). Id., pp. 34-35.

Turning to the Staff's position regarding the various Edgewater-5 issues, it states that, based on the evaluation conducted in the re-opened portion of Case No. U-16366, it now believes that "$49.3 million represents a just and reasonable imputed value" for WEPCo's past ownership interest in Edgewater-5, which would jump to $95.7 million if the facility's operating agreement was extended. Staff's initial brief, p. 48. Moreover, while it concedes that the Commission's final ruling regarding the level of those proceeds has not been determined, the Staff recommends that Michigan's share of the Edgewater-5 sales proceeds be credited to retail tariff customers using a three-month negative surcharge, and further proposes various reporting and accounting procedures and requirements with regard to that negative surcharge.[24] Nevertheless, it asserts that

[24] The Staff recommends that WEPCo file a report in this case "detailing the net proceeds, the accrual interest, and the calculation of the negative surcharge no later than 15 days after the date of issuance of the final order in this proceeding." Staff's initial brief, p. 53. Then, it continues, "any interested person may file comments regarding the accuracy of the calculation within 14 days," and "absent further orders from the Commission, WEPCo shall implement the negative surcharge at the beginning of the first billing cycle that is more than 30 days following the filing of this report. Id., pp. 53-54. The Staff also recommends that:

> [T]he negative surcharge remain in effect until the amount to be returned to customers is fully refunded through one or more complete billing cycles. WEPCo should accrue and apply interest during the entire duration of the negative surcharge at 0.99%. Within 15 days of termination of the negative surcharge, WEPCo should file a letter in [Cases Nos.] U-16366 and U-16830 stating that the negative surcharge was terminated, and provide a final reconciliation of the negative surcharge. Any residual amount determined to be over-refunded to customers should be captured and reflected through WEPCo's next [PSCR] case as a separate line item. Based upon the foregoing procedure, there will be no requirement for WEPCo to seek Commission authority to reconcile any residual proceeds of the negative surcharge.

the Company's proposal to offset various transaction costs, net income tax, and prior lease payments for ERGS-2 from the level of imputed proceeds ultimately established by the Commission in Case No. U-16366, should be rejected as unreasonable and unjustified. See, Staff's initial brief, pp. 49-53.

The ALJ agrees with the Staff (and, albeit to a lesser extent, the Mines) regarding the outstanding issues concerning how to best handle the Edgewater-5 sale proceeds.

With regard to the utility's request to receive an off-set for the transaction costs stemming from the sale of its 25% ownership interest in Edgewater-5, it bears noting that, prior to the submission of its application in this rate case proceeding, the Company does not appear to have ever requested recovery of any level of transaction costs associated with that sale. Also, as reflected on Exhibit MIN-33 (which is a discovery response initially provided in Case No. U-16366), WEPCo explicitly stated that it would not seek recovery from ratepayers of any transaction costs arising from its sale of the Company's 25% interest in that facility. Thus, as correctly noted by the Mines, "the reasonableness of the level of claimed transaction costs was never reviewed by the intervening parties." Mines' initial brief, p. 33. Moreover, as accurately noted by the Staff's witness on this topic, Ms. Sandhu:

> In Case No. U-16366, Company witness Mary L Wolter testified that WEPCo did not request recovery of tranaction costs. In its Initial Brief in the same proceeding, the Company stated that it is not requesting recovery of transaction costs that will be incurred as a result of the sale. Since WEPCo committed to the parties and to the Commission in Case No. U-16366 that it was not seeking recovery of the transaction costs related to the sale of its interest in [Edgewater-5], the Staff believes that the Company's request to do so in this proceeding is inappropriate. Parties to Case No. U-16366 evaluated the financial impact on ratepayers

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Id., p. 54.

> based on that representation of the transaction. The Commission evaluated the record evidence, including WEPCo's representation that it would not seek to recover transaction costs, to arrive at its decision to approve the proposed sale. WEPCo, by requesting that [Edgewater-5] transaction costs be recovered in this proceeding, would (if approved) be altering the financial impact that the [plant's] sale had on its ratrepayers. In addition, the Commission in its original order dated December 2, 2010 in Case No. U-16366 directed WEPCo to address its proposed <u>treatment</u> of the net proceeds over book value, not to reexamine the costs that should be deducted to arrive at the <u>amount</u> of the net proceeds.

3 Tr. 565-566 (emphasis in original). For the reasons expressed by the Mines and the Staff, the ALJ finds that the Commission should reject the utility's request for an offset to the transaction costs stemming from the sale of its 25% ownership interest in Edgewater-5.

The ALJ's view of the utility's basis for requesting that the Commission reduce any imputed premium proceeds by 40% to reflect the allegedly-related income tax effect is equally unpersuasive. As noted by the Staff, the Commission's December 2, 2010 order in Case No. U-16366:

> Directed WEPCo to address its proposed treatment of the net proceeds over book value, not to reexamine the costs that should be deducted to arrive at the amount of the net proceeds.

Staff's initial brief, p. 51. Thus, as with the Company's request with regard to various transaction costs, the ALJ finds that any asserted tax-related expense should not be netted against the Michigan ratepayers' portion of the Edgewater-5 sale proceeds, and therefore recommends that the Commission deny the utility's request to do so.

Turning next to WEPCo's request to net the unrecovered ERGS-2 lease payments from the potential refund of the Michigan-related portion of the Edgewater-5 proceeds, the ALJ is not persuaded by the Company's claim to the effect that there is no harm in comingling the ratepayers' financial benefits from the sale of Edgewater-5 with the financial liability arising from ERGS-2's pre-operational date lease payments. As correctly noted by the Staff, the calculation and treatment of the Edgewater proceeds [in Case No. U-16366] "began as a separate and distinct proceeding," and "any issues surrounding [ERGS-2] had no bearing on the outcome of that proceeding." Staff's reply brief, p. 7. The ALJ finds that undue and unnecessary confusion could arise from commingling unrelated matters such as these. As a result, it is recommended that the Commission reject WEPCo's request to net all unrecovered ERGS-2 lease payments from the refund otherwise due to Michigan-based ratepayers with their portion of the Edgewater-5 proceeds.

The next matter to address concerns WEPCo's proposal to share, on a 50/50 basis, the Michigan ratepayers' portion of the imputed purchase price ultimately assigned by the Commission to the Company's sale of its 25% interest in Edgewater-5. On this issue, the ALJ agrees with the Mines and the Staff, and concludes that all of the sale proceeds in question should be distributed to the utility's ratepayers, rather than shared (on the 50/50 basis proposed by WEPCo or otherwise) with the Company's shareholders. As noted by the Mines, the utility's former ownership interest in Edgewater-5 was funded through the rates assessed to its customers ever since the facility commenced commercial operation. For its part, the Company (and, thus, its shareholders) received a return of and on the investment made in the plant from that date forward, therefore making them financially whole, in both the Mines' view and that of the ALJ. See, e.g., Mines' initial brief, p. 34. Furthermore, it appears that splitting the Edgewater-5 sales proceeds between the utility and its ratepayers could be viewed as conflicting with the Commission's prior treatment of proceeds derived from Consumers' sale of the Palisades Nuclear Plant (in Case No. U-14992) and those arising from WEPCo' sale of the Point Beach Nuclear Plant (in Case No. U-15220).

Turning to the final issue with regard to the Edgewater-5 asset sale, the ALJ finds that the Mine's proposal to allocate the asset's imputed purchase price revenue to WEPCo's Michigan-jurisdictional end-use customers on an energy-only basis, and to use it solely as an offset to the revenue deficiency computed in this case, should be rejected, and that the treatment proposed by the Staff and agreed to by the Company should be adopted instead. As WEPCo also correctly noted with regard to both the DOE settlement credits and the Bechtel liquidated damages issues addressed earlier, a specific crediting mechanism like that proposed by the Staff is preferable to a mere reduction in base rates, largely because the crediting mechanism can be crafted to eliminate the risk of over- or under-crediting the amount to be returned to ratepayers. The ALJ again agrees with this theory, and recommends that the Commission approve--for use in this case--the Staff's proposed negative surcharge, as well as its attendant procedures and reporting requirements.

IX.

CONCLUSION

Based upon the foregoing, the ALJ recommends that the Commission issue an order adopting each of the findings and conclusions set forth above. These include findings to the effect that: (1) WEPCo's total electric utility rate base is $6,298,174,921, which corresponds to $354,886,352 on a Michigan-only jurisdictional basis; (2) the Company's overall rate of return should be set at 6.25%, including a cost of common equity of 9.95%; (3) WEPCO's adjusted NOI for the 2012 projected test year would be $329,734,274 on a total electric utility basis, or $12,917,611 on a Michigan jurisdictional basis; and (4) the base rates, overall rate of return, and projected NOI recommended for approval in this case would thus give rise to adjusted gross revenue deficiency (after accounting for the ERGS increment at 100% as opposed to 108%, and the previously-recommended Act 295 RE adjustment) of $10,010,522 on a jurisdictional basis. As a result, the ALJ recommends that the Commission authorize WEPCo to increase its Michigan-specific rates for the generation and distribution of electricity in the net amount of $10,010,522 annually.

Finally, it should be noted that any arguments not specifically addressed in this PFD were deemed to be irrelevant to the ALJ's ultimate findings and conclusions.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Mark E. Cummins

Digitally signed by Mark E. Cummins
DN: cn=Mark E. Cummins, c=US, email=cumminsm1@michigan.gov
Date: 2012.04.30 15:27:49 -04'00'

Mark E. Cummins
Administrative Law Judge

DATE, April 30, 2012
Lansing, Michigan
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